EXHIBIT LIST

A – ADMINISTRATIVE

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

B – 2011 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	ESM Calculations	K. Culbert R. Small
		2	ESM Calculations and Required Rate of Return 2011 Historical Year	K. Culbert R. Small
		3	Utility Earnings – Comparison of 2011 Historical Year to 2007 Board Approved	K. Culbert R. Small
		4	Utility Earnings – Reconciliation of 2011 Utility Income to Audited EGDI Consolidated Income	K. Culbert R. Small
		5	Unregulated Storage Review	K. Culbert B. Pilon
	2	1	Ontario Utility Rate Base – Comparison of 2011 Historical Year to 2010 Historical Year	K. Culbert R. Small
		2	Ontario Utility Rate Base – Comparison of 2010 Historical Year to 2009 Historical Year	K. Culbert R. Small

EXHIBIT LIST

B – 2011 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	2	3	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2011 Historical Year	K. Culbert R. Small
		4	Comparison of Utility Capital Expenditures Actual 2011 and Actual 2010	L. Au D. Kelly
		5	Comparison of Utility Capital Expenditures Actual 2010 and Actual 2009	L. Au D. Kelly
	3	1	Utility Operating Revenue 2011 Historical Year	K. Culbert R. Small
		2	Comparison of Gas Sales and Transportation Volume by Rate Class 2011 Actual to 2011 Board Approved Budget	P. Baxter I. Chan
		3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2011 Historical Year to 2011 Board Approved Budget	P. Baxter I. Chan
		4	Customers Meters, Volumes and Revenues by Rate Class 2011 Actual	P. Baxter I. Chan
		5	Details of Other Revenue 2011 Historical Year to 2010 Historical Year	R. Lei
		6	Details of Other Revenue 2010 Historical Year to 2009 Historical Year	R. Lei

EXHIBIT LIST

B – 2011 HISTORICAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	4	1	Operating Cost 2011 Historical Year	K. Culbert R. Small
		2	Operating and Maintenance Expense by Department Ending December 2011	R. Lei A. Patel
	5	1	Required Rate of Return 2011 Historical Year	K. Culbert R. Small
		2	Utility Income 2011 Historical Year	K. Culbert R. Small
		3	Cost of Capital 2011 Historical Year	K. Culbert R. Small

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	1	Balances Requested for Clearance at October 1, 2012	K. Culbert R. Small
		2	Gas Distribution Access Rule Cost Deferral Account explanation	K. Culbert R. Small
		3	Municipal Permit Fees Deferral Account explanation	K. Culbert R. Small
		4	Average Use True Up Variance Account explanation	P. Baxter I. Chan

EXHIBIT LIST

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	5	MDVMDA	K. Culbert R. Small
		6	2011 OHCVA	K. Culbert R. Small
	2	1	Clearance of Deferral and Variance Account Balances	J. Collier A. Kacicnik M. Kirk
		2	Derivation of Proposed Unit Rates	J. Collier A. Kacicnik M. Kirk

D – REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2011	B. Yuzwa
		2	Enbridge Gas Distribution Inc. Management's Discussion and Analysis – December 31, 2011	B. Yuzwa
		3	2011 Distributed Energy, Green Energy Initiatives and Fuel Cell Activities	T. Maclean
	2	1	Regulated / Unregulated Storage Cost Allocation	R. Feingold Black & Veatch

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

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

A P P L I C A T I O N

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

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

3. As of January 1, 2012, Enbridge began the fifth year of a five year Incentive Regulation plan ("IR Plan") approved by the Board in EB-2007-0615. The Board-approved Revised Settlement Agreement in EB-2007-0615 (the "Settlement Agreement") provides that Enbridge shall maintain the deferral and variance accounts listed in Appendix B to the Settlement Agreement for the term of the IR Plan. The Board's Decision and Order in EB-2010-0146 dated November 25, 2010 approved the establishment of 2011 deferral and variance accounts consisting of: (a) the deferral and variance accounts listed in Appendix B of the Settlement Agreement; and (b) the additional accounts approved in Enbridge's 2010 rates proceeding, EB-2009-0172.

4. Among the deferral and variance accounts listed in Appendix B to the Settlement Agreement is the Earnings Sharing Mechanism Deferral Account ("ESMDA"). The Settlement Agreement states that Enbridge will file 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.

5. Enbridge applies to the Board for such final, interim or other Orders as may be necessary or appropriate for the clearance or disposition of the 2011 ESMDA and the other Board-approved 2011 deferral and variance accounts, all of which are listed in Appendix A to this Application.

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

7. 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 May 11, 2012 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: ______[original signed]________________

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at March 31, 2012 Principal ($000's)	Col. 2 Actual at March 31, 2012 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2012 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2012 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2010 DSMVA	(2,717.1)	(93.6)	(2,717.1)	(113.4) [1]
2.	Lost Revenue Adjustment Mechanism	2010 LRAM	-	-	(42.9)	(0.5) [1]
3.	Shared Savings Mechanism V/A	2010 SSMVA	-	-	4,155.3	25.5 [1]
4.	Class Action Suit D/A	2012 CASDA	4,709.5	449.4	4,709.5	484.2 [2]
5.	Deferred Rebate Account	2011 DRA	(308.7)	(1.9)	(308.7)	(4.3)
6.	Gas Distribution Access Rule Costs D/A	2011 GDARCDA	226.6	1.7	2,758.1	- [3]
7.	Ontario Hearing Costs V/A	2011 OHCVA	(1,031.9)	(4.1)	(1,031.9)	(11.9) [4]
8.	Unbundled Rate Implementation Cost D/A	2011 URICDA	139.7	1.5	139.7	2.7
9.	Municipal Permit Fees D/A	2011 MPFDA	1,082.0	-	429.4	- [3]
10.	Average Use True-Up V/A	2011 AUTUVA	(2,948.9)	(10.8)	(2,948.9)	(32.4) [5]
11.	Tax Rate and Rule Change V/A	2011 TRRCVA	(1,200.0)	(9.1)	(1,200.0)	(18.1)
12.	Earnings Sharing Mechanism D/A	2011 ESMDA	(14,100.0)	(51.8)	(14,300.0)	(155.6) [6]
13.	Mean Daily Volume Mechanism D/A	2012 MDVMDA	152.1	0.2	616.1	- [7]
14.	Mean Daily Volume Mechanism D/A	2011 MDVMDA	2,537.3	29.2	-	- [7]
15.	Mean Daily Volume Mechanism D/A	2010 MDVMDA	1,280.4	23.5	-	- [7]
16.	Mean Daily Volume Mechanism D/A	2009 MDVMDA	42.4	0.8	-	- [7]
17.	Electric Program Earnings Sharing D/A	2011 EPESDA	(247.5)	(0.9)	(247.5)	(2.7)
18.	Ex-Franchise Third Party Billing Services D/A	2011 EFTPBSDA	(234.4)	(0.9)	(234.4)	(2.7)
19.	Open Bill Service Deferral Account	2012 OBSDA	153.5	1.3	87.7	1.2 [8]
20.	Open Bill Access Variance Account	2012 OBAVA	139.0	1.3	79.4	1.1 [8]
21.	Total non commodity related accounts		(12,326.0)	335.8	(10,056.2)	173.1
	Commodity Related Accounts					
22.	Transactional Services D/A	2011 TSDA	(7,357.0)	(49.2)	(7,357.0)	(103.2)
23.	Unaccounted for Gas V/A	2011 UAFVA	8,536.2	24.5	8,536.2	87.5
24.	Storage and Transportation D/A	2011 S&TDA	(910.0)	(8.7)	(910.0)	(15.3)
25.	Total commodity related accounts		269.2	(33.4)	269.2	(31.0)
26.	Total Deferral and Variance Accounts		(12,056.8)	302.4	(9,787.0)	142.1

Notes:

1. The final 2010 DSMVA, LRAM, and SSMVA balances to be cleared will be those approved in EB-2012-0192.
2. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years (2008 - 2012). The 2008 installment was cleared in July and August 2008, the 2009 installment was cleared in April and May 2010, the 2010 installment was cleared in January 2011, and the 2011 installment was cleared in October 2011. The Company is requesting clearance of the 2012, or fifth and final installment in this proceeding.
3. The forecast 2011 GDARCDA and 2011 MPFDA clearance amounts are the result of revenue requirement calculations found in evidence at Ex.C-1-2 and C-1-3.
4. The OHCVA calculation is found in evidence at Ex.C-1-6.
5. The AUTUVA explanation is found in evidence at Ex.C-1-4.
6. The ESMDA explanation is found in evidence at Ex.B-1-1 and B-1-2.
7. The forecast 2012 MDVMDA clearance amount is the result of a revenue requirement calculation, found in evidence at Ex. C-1-5, based on the consolidated balance of the 2009 through 2012 MDVMDA's.
8. The forecast OBSDA and OBAVA balances are in accordance with the EB-2009-0043 approved Settlement Agreement.

APPROVALS REQUESTED

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

   a) The Company has filed the balances at March 31, 2012, of Board approved deferral and variance accounts and is requesting approval for their clearance commencing October 1, 2012, (Exhibit C, Tab 1, Schedule 1). While the EB-2007-0615 Settlement Agreement anticipated that clearance of such accounts would occur in conjunction with each following fiscal year's July 1st QRAM proceeding, it seems apparent from the process timelines experienced in each of EGD's 2008, 2009, and 2010 proceedings that clearance on October 1st is a more reasonable expectation. Clearance of the balances is proposed as a one time rider adjustment to customers' bills coincident with the Company's October 1, 2012 Quarterly Rate Adjustment Mechanism filing which deals 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 2011 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 2011 financial statements are filed within Exhibit B, Tabs 1 through 5 and Exhibit D, Tab 1[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.

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[1] The review/study of Storage Cost Allocations was not complete for the year end ESM results. EGD'sdetermination of the impact of the study results in a $0.2 million increase to the ESM result calculated at year end.

Witnesses: K. Culbert
R. Small

d) In order to facilitate the clearance of the deferral and variance accounts through a rate rider within the specific rate classes within the Company's October 1, 2012 QRAM proceeding, a Board Decision or approval is required by approximately August 15th, 2012.

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

3. The Company has filed the ESM calculations within this application at Exhibit B, Tab 1, Schedules 1 and 2. The Company requests that the Board issue a procedural order outlining the timelines of the next steps of the proceeding upon receipt of this application.

Witnesses: K. Culbert
R. Small

CURRICULUM VITAE OF
LINDA AU

Experience:	Enbridge Gas Distribution Inc.
	Capital Budget Manager 2007
	Capital Budget Supervisor 1995
	Revenue and Gas Cost Analyst 1991
	Canada Post Corporation
	Operations Planning and Budget Officer 1990
	Financial Analyst 1988
	Queen Elizabeth Hospital
	Senior Accountant 1986
Education:	Certified General Accountant CGA Ontario 1991
	Bachelor of Business Management Ryerson 1986
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0008 EB-2010-0042 EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2006-0034 RP-2005-0001

CURRICULUM VITAE OF
PAUL BAXTER

Experience:	Enbridge Gas Distribution Inc.
	Supervisor, Margin Accounting, and Gas Analytics 2011
	Supervisor, Margin Accounting, Business Performance and Analytics 2010
	Supervisor, Margin Budgets and Accounting 2007
	Supervisor, Margin Planning and Analysis 2006
	Analyst, Volumetric Analysis and Budgets 2004
Education:	Continuing Studies in Accounting University of Western Ontario, 2003
	Master of Arts in Economics Queen's University, 2002
	Bachelor of Arts (Honours) in Economics University of Western Ontario, 2001
Memberships:	Toronto Association for Business & Economics
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
ROBERT ALAN BOURKE, CMA

Experience: Enbridge Gas Distribution Inc.

Manager Regulatory Proceedings
2004

Manager Budget and Administration – Operations
2003

Manager Regulatory Accounting
1998

Senior Analyst Regulatory Accounting
1995

Supervisor Revenue and Gas Cost
1992

Centra Gas (Ontario) Inc.

Supervisor, Budget Administration
1992

Thornhill Glass & Mirror Inc.

Controller
1988

The Consumer Gas Company Limited

Manager System Customer Billing
1987

Management Trainee
1986

Supervisor Income and Cash Budget
1982

Asst. Supervisor Income and Cash Budget
1980

Education: Certified Management Accountant (CMA), 1981

Memberships: The Society of Management Accountants Ontario

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
EB-2011-0226
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2008-0219
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
RP-1999-0001
EBRO 497
EBO 179-14/15

CURRICULUM VITAE OF
IRENE CHAN

Experience: Enbridge Gas Distribution

Manager, Margin Accounting, and Gas Analytics
2011

Manager, Margin Accounting, Business Performance and Analytics
2010

Manager, Margin Budgets and Accounting
2007

Manager, Margin Planning and Analysis
2006

Manager, Volumetric Analysis and Budgets
2003

Supervisor, Volumetric Analysis
2001

Senior Analyst, Volumes Knowledge Centre
2000

Economic Analyst, Economic Studies
1998

Queen's University

Instructor, Economics Department
1997

Research/Teaching Assistant, Economics Department
1992-1997

International Monetary Fund

Summer Intern, Research Department
1996

Consultant, Research Department
1994

Bank of Canada

Research Assistant, Research Department
1991

Education:	Certified Management Accountant, The Society of Management Accountants of Canada, 2006
	Ph.D. in Economics Queen's University, 1998
	Master of Arts in Economics Queen's University, 1993
	Bachelor of Arts (Honours) in Economics University of Western Ontario, 1991
Memberships:	Toronto Association for Business & Economics The Society of Management Accountants of Canada
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0008 EB-2010-0042 EB-2009-0172 EB-2009-0055 EB-2008-0219 EB-2007-0615 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Design
2003

Manager, Rate Research
2000

Senior Rate Research Analyst
1996

Centra Gas Ontario Inc.

Manager, Rate Design
1995

Supervisor, Cost of Service Studies
1990

Education: Bachelor of Business Management
Ryerson Polytechnical Institute, 1988

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
EB-2010-0146
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0106
EB-2006-0034
EB-2005-0001
RP-2003-0203
RP-2003-0048
RP-2002-0133
RP-2001-0032
RP-2000-0040
EBRO 489
EBRO 474-B, 483,484
EBRO 474-A
EBRO 474
EBRO 471

(Régie de l’énergie/Régie du gaz naturel)
R-3758-2011
R-3724-2010
R-3692-2009
R-3665-2008
R-3637-2007
R-3621-2006
R-2587-2005
R-3537-2004
R-3464-2001
R-3446-2000

CURRICULUM VITAE OF
KEVIN CULBERT

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
2003

Senior Analyst, Regulatory Accounting
1998

Analyst, Regulatory Accounting
1991

Assistant Analyst, Regulatory Accounting
1989

Budgets – Capital Clerk, Budget Department
1987

Accounting Trainee, Financial Reporting
1984

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

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
EB-2011-0226
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0219
EB-2008-0104/EB-2008-0408
EB-2007-0615
EB-2006-0034
EB-2005-0001
RP-2003-0203

CURRICULUM VITAE OF
ANTON KACICNIK

Experience: Enbridge Gas Distribution Inc.

Manager, Rate Research & Design
2007

Manager, Cost Allocation
2003

Program Manager, Opportunity Development
1999

Project Supervisor, Technology & Development
1996

Pipeline Inspector, Construction & Maintenance
1993

Education: Bachelor of Applied Science (Civil Engineering)
University of Waterloo, 1996

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172
EB-2009-0055
EB-2008-0106
EB-2008-0219
EB-2007-0615
EB-2007-0724
EB-2006-0034
EB-2005-0551
EB-2005-0001

(RÉGIE DE L'ÉNERGIE)
R-3724-2010
R-3665-2008
R-3637-2007
R-3621-2006
R-3587-2006
R-3537-2004

CURRICULUM VITAE OF
D. A. KELLY

Experience: Enbridge Gas Distribution Inc.

Manager, Capital Effectiveness
2011

Manager, Capital Budgets and Accounting
2007

Manager, Operational and Capital Budgets
2005

Manager, Cost Awareness and Analysis
2001

Senior Analyst, Operation and Maintenance
2000

Supervisor, Management Reporting
1997

Supervisor, Corporate Reporting
1992

Analyst, Financial Reporting
1991

Supervisor, Non-Utility Accounting
1989

Financial Statements Accountant
1988

Internal Audit Assistant
1987

Accounting Trainee
1985

Another Company

Corporate Loans, Guaranty Trust
1983

General Accounting, Consumers Glass
1981

Education:	Bachelor of Business Management Ryerson University, 1985
	Certified Management Accountant Society of Management Accountants, 1987
Memberships:	Society of Management Accountants of Ontario
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2006-0034 EB-2005-0001 RP-2003-0203 RP-2002-0133 RP-2001-0032

CURRICULUM VITAE OF
MATTHEW KIRK

Experience:	Enbridge Gas Distribution Inc.
	Senior Rate Design Analyst, Regulatory Affairs 2010
	Rate Design Analyst, Regulatory Affairs 2009
	Market Analyst, Economic and Market Analysis 2006
Education:	Master of Arts (Economics) Wilfrid Laurier University, 2006
	Bachelor of Arts (Honours Economics) McMaster University, 2005
Memberships:	Canadian Association of Business Economists (CABE)
Appearances:	(Ontario Energy Board) EB-2011-0354

CURRICULUM VITAE OF
RAYMOND LEI

Experience: Enbridge Gas Distribution Inc.

Manager, Budgets and Business Support
2010

Manager, Corporate Budgets and Analysis
2007

Manager, Financial Analysis
2007

Senior Analyst, Planning and Projects
2005

Rogers Wireless Inc.

Senior Analyst, Budgets and Forecast
2001

Royal LePage Relocation Services Ltd.

Financial Analyst
2000

Kodak (China) Limited

Business Analyst
1995

Education: Certified General Accountant
Certified General Accountants of Ontario, 2005

Master of Business Administration
York University, 2000

Bachelor of Arts in Commerce and Economics
Sichuan University, China

Memberships: Certified General Accountant, Ontario

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
EB-2011-0008
EB-2010-0146
EB-2010-0042
EB-2009-0172

CURRICULUM VITAE OF
TREVOR MACLEAN

Experience:

Enbridge Gas Distribution Inc.

Director, Business & Market Development
2008

Enbridge Gas New Brunswick

Manager, Distribution Operations
2006

Manager, Sales & Marketing
2004

RLG International

Consultant
2000

825929 Alberta Ltd

Consultant
1997

ISM (IBM Global Services)

Director, Systems Integration
1995

Manager Operations, Systems Integration
1994

National Defence/Canadian Forces

Military Officer
1986

Education:

Master of Business Administration
Queen's University, 1995

Bachelor of Arts (Special)
University of Alberta, 1986

Appearances:

(Ontario Energy Board)
EB-2011-0354

CURRICULUM VITAE OF
ASHA PATEL

Experience:	Enbridge Gas Distribution Inc.
	Supervisor of Finance Operational Support 2011
	Supervisor of O&M Budgets 2011
	Supervisor of External Reporting and Pensions 2008
	Ernst & Young LLP
	Senior Staff Accountant 2008
	Staff Accountant 2006
Education:	Chartered Accountant Institute of Charted Accountants of Ontario, 2008
	Masters of Accounting University of Waterloo, 2006
	Bachelor of Arts, Honours Accountancy Co-op University of Waterloo, 2005
Memberships:	Institute of Chartered Accountants of Ontario
Appearances:	(Ontario Energy Board) EB-2011-0354 EB-2011-0008

CURRICULUM VITAE OF
BRAD S. PILON

Experience:	Enbridge Gas Distribution Inc.
	Manager, Finance and Administration Gas Storage 2001
	Manager, Administration - Gas Storage 1991
	Tecumseh Storage Analyst 1988
	Manager, Marketing Studies 1986
	Financial Analyst, Exploration 1982
Education:	Executive Education Program for the Natural Gas Industry University of Colorado, 1990
	Graduate Studies Masters of Business Administration Program University of Western Ontario, 1979-1980
	Bachelor of Arts University of Western Ontario, 1979
Memberships:	Ontario Petroleum Institute
Appearances:	(Ontario Energy Board) EB-2011-0354 RP-2003-0203 EBRO 466 EBRO 455

CURRICULUM VITAE OF
RYAN SMALL

Experience: Enbridge Gas Distribution Inc.

Senior Analyst, Regulatory Accounting
2006

Analyst, Regulatory Accounting
2004

Supervisor, Gas Cost Reporting
2001

Senior O&M Clerk
2000

Bank Reconciliation Clerk
1999

Accounting Trainee
1998

Education: Certified Management Accountant,
The Society of Management Accountants of Ontario, 2003

Diploma in Accounting,
Wilfrid Laurier University, 1997

Bachelor of Arts in Economics
The University of Western Ontario, 1996

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0008

CURRICULUM VITAE OF
BARRY C. YUZWA

Experience: Enbridge Gas Distribution Inc.

Director, Finance & Control
2010

Enbridge Inc.

Senior Director, Chief Audit Executive
Audit Services & Internal Controls
2007

Director, Audit Services
1999

Safeway Inc./Canada Safeway Limited

Manager, Corporate Audit Services
1991

Deloitte & Touche

Audit Manager
1987

Education: Certified Internal Auditor
Institute of Internal Auditors
2003

Chartered Accountant
Canadian Institute of Chartered Accountants
1986

Bachelor of Commerce-Accounting
University of Calgary
1983

Memberships: Canadian Institute of Chartered Accountants
Institute of Chartered Accountants of Alberta
Institute of Chartered Accountants of Ontario
Institute of Internal Auditors
Financial Executives International, Canada
Corporate Executive Board, Audit Directors and Risk Management Advisory Council
University of Calgary, Haskayne School of Business, Mentorship Program
Enbridge Inc. Mentorship Program

Appearances: (Ontario Energy Board)
EB-2011-0354
EB-2011-0277
EB-2011-0008

2011 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. The 2011 Earnings Sharing amount included in Enbridge Gas Distribution Inc's. Fiscal 2011 year end audited statements was $14.1 million, whereas the amount being requested for approval and clearance in this application is $14.3 million[1]. In order to meet year end timing obligations, estimates for elements impacting the accrual are sometimes required in lieu of complete or detailed analyses along with the rounding of various actual amounts into $millions for regulatory presentation. Following the year end close process however, completion of analyses are performed for elements where estimates were used along with rounding finalizations, in order to ensure the earnings sharing amount is accurate. If required and appropriate, an adjustment is made to the earnings sharing results, which ultimately is reflected in the following year financial statements. The process followed is the same each year, which for Fiscals 2009 and 2010, led to adjustments to the earnings sharing amounts included in the earnings sharing applications versus year-end financial statements. In 2011, the study of the allocation of costs between the regulated and unregulated storage processes was not completed by year end. The impact of incorporating the allocation process findings as suggested in the Black and Veatch storage cost allocation study results in an increase in the ESM accrual of $0.2M. The Black and Veatch study is found in evidence at Exhibit B, Tab 1, Schedule 5.

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 in Exhibit B, Tab 1, Schedule 2.

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[1] The review/study of Storage Cost Allocations was not complete for the year end ESM results. EGD's determination of the impact of the study results in a $0.2 million increase to the ESM result calculated at year end.

Witnesses: K. Culbert
R. Small

3. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified in the EB-2007-0615 Board Approved Settlement Agreement (Ex. N1, T1, S1, p. 27);

   - if in any calendar year, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated annually by the application of the Board's ROE Formula in any year of the IR Plan, then the resultant amount shall be shared equally (ie., 50/50) between Enbridge and its ratepayers;
   - for the purposes of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings;
   - all revenues that would otherwise be included in revenue in a cost of service application shall be included in revenues in the calculation of the earnings calculation and only those expenses (whether operating or capital) that would be otherwise allowable as deductions from earnings in a cost of service application, shall be included in the earnings calculaton;

4. In the EB-2007-0615 Settlement Agreement the Parties acknowledge that the following shareholder incentives and other amounts are outside the ambit of the ESM:

   - amounts in respect of the application of the Shared Savings Mechanism ("SSM") and the LRAM;
   - amounts related to storage and transportation related deferral accounts; and
   - the Company's 50% share of the tax amount calculated in association with expected tax rate and rule changes as per the settlement (Ex. N1, T1, S1, p. 23).

Witnesses: K. Culbert
R. Small

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

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

<u>Part A)</u>

7. The level of utility income, $291.7 million (Line 19) divided by the level of utility rate base, $3,957.0 million (Line 24) generates a utility return on rate base of 7.372% (Line 25).

8. When compared to the Company's required rate of return of 6.854% (Line 26), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.518% (Line 27) on total rate base.

9. As shown in Lines 28 through 30, the sufficiency of 0.518% multiplied by the rate base of $3,957.0 million, produces a net over earnings or sufficiency of $20.50 million which from a pre-tax perspective, ($20.50 million divided by the reciprocal, 71.75%, of the corporate tax rate which is 28.25%) shows a $28.57 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Part B) (Confirming the Calculated Earnings Sharing)

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

11. The $348.7 million (Line 33) of utility income before income tax, less utility taxes of $57.0 million (Line 38), produces the $291.7 million of utility income used in part A) above (at Line 19).

12. In order to determine utility net income applicable to a deemed common equity percentage in rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $291.7 million utility income.

13. These reductions are shown at Lines 34 to 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 $147.8 million, shown at Line 39.

14. The $147.8 million, divided by the deemed common equity level of $1,424.5 million (Line 40, calculated as 36% of the $3,957.0 million rate base) produces a return on equity of 10.376% (Line 42). When comparing the 10.376% achieved return on equity to the threshold ROE percentage of 8.94% (Line 41), which is the Board approved formula return on equity for 2011 of 7.94% plus the approved 100 basis point dead band, there is a sufficiency in ROE of 1.44% (Line 43).

15. The 1.44% multiplied by the common equity level of $1,424.5 million (Line 40) produces a net over earnings or sufficiency of $20.51 million which from a pre-tax perspective, ($20.51 million divided by the reciprocal, 71.75%, of the corporate tax rate) shows a $28.59 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence

references. The $0.02 million negligible difference between the part A) and part B) overearnings calculations is due to rounding.

<u>Process Description</u>

16. The calculation of utility earnings and any sharing requirement starts with financial results contained in 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, and
    - elimination of corporate income taxes due to the determination of income taxes specific to utility results,

18. In addition, EGD has made the appropriate adjustments in relation to non standard rate regulated items which the Board has either decided in the past, were agreed to in the EB-2007-0615 approved settlement, or are required in order to determine an appropriate utility return on equity in the Incentive Regulation versus Cost of Service construct. Examples are:
    - rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
    - rate base disallowance from RP-2002-0133 (shared assets),
    - exclusion of non-utility or unregulated activities,

Witnesses: K. Culbert
R. Small

- elimination of EGD share of shared savings mechanism,
- elimination of EGD share of transactional services, and
- elimination of EGD share of tax rate and rule changes.

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

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2011

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	1,978.4
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	411.2
4.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,383.7
5.	Gas Distribution Margin		1,005.9
6.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	1.5
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	40.6
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	0.8
9.	Total - TC&S, Oth. Rev. & Inc.		42.9
10.	Operations, Maintenance & Administration	(Ex.B,T5,S2,P1,Col.1,line 9)	360.5
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	276.6
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	2.8
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)	22.3
15.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 14)	37.6
16.	Total O&M, Depr., & other		700.1
17.	Utility Income before Income Tax	(line 5 + line 9 - line 16)	348.7
18.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	57.0
19.	**Utility Income**		**291.7**
20.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	6,064.1
21.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(2,398.4)
22.	Net plant		3,665.7
23.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 12)	291.3
24.	**Utility Rate Base**		**3,957.0**
25.	Indicated Return on Rate Base %	(line 19 / line 24)	7.372%
26.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	6.854%
27.	(Deficiency) / Sufficiency %		0.518%
28.	Net Earnings (Deficiency) / Sufficiency	(line 27 x line 24)	20.50
29.	Provision for Income Taxes		8.07
30.	Gross Earnings (Deficiency) / Sufficiency	(line 28 divide by 71.75%)	28.57
31.	**50% Earnings sharing to ratepayers**	(line 30 x 50%)	**14.28**
32.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
33.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 18)	348.7
34.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	139.7
35.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	1.8
36.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	2.4
37.	Net Income before Income Taxes		204.8
38.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 19)	57.0
39.	Net Income Applicable to Common Equity	(line 37 - line 38)	147.8
40.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	1,424.5
41.	Approved ROE %	(EB-2007-0615 for Earnings Sharing 7.94% + 100 bp)	8.940%
42.	Achieved Rate of Return on Equity %	(line 39 divide by line 40)	10.376%
43.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.44%
44.	Net Earnings (Deficiency) / Sufficiency	(line40 x line 43)	20.51
45.	Provision for Income Taxes		8.08
46.	Gross Earnings (Deficiency) / Sufficiency	(line 44 divide by 71.75%)	28.59
47.	**50% Earnings sharing to ratepayers**	(line 46 x 50%)	**14.29**

Witnesses: K. Culbert
R. Small

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS
FOR FISCAL YEAR 2011

Line No.		Col. 1 2011 Actual Normalized $Millions	Col. 2 2007 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	1,978.4	2,369.1		
2.	Transportation revenue	411.2	748.8		
3.	Transmission, compression & storage	1.5	1.9		
4.	Gas costs	1,383.7	2,174.6		
5.	Distribution margin	1,007.4	945.2	62.2	a)
6.	Other revenue	40.6	34.3	6.3	b)
7.	Other income	0.8	0.2	0.6	c)
8.	O&M	360.5	326.2	(34.3)	d)
9.	Depreciation expense	276.6	227.3	(49.3)	e)
10.	Other expense	63.0	56.4	(6.6)	f)
11.	Income taxes	57.0	85.8	28.8	g)
12.	Utility Income	291.7	284.0	7.7	
13.	LTD & STD costs	141.5	165.8	24.3	h)
14.	Preference share costs	2.4	5.0	2.6	h)
15.	Return on Equity @ 8.94%[1] in 2011, 8.39% in 2007	127.3	113.2	(14.1)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	20.5	(0.0)	20.5	
17.	Provision for taxes on Earnings Over / (Under)	8.1	(0.0)	8.1	
18.	Gross Earnings Over / (Under)	28.6	(0.0)	28.6	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,424.5			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	147.8			
21.	EGD normalized Return on Equity	10.38%			

[1] 7.94% as per Board Approved formula using October 2010 consensus forecast, plus 100 basis points as per 2008 incentive regulation Board Approved agreement.

Witnesses: K. Culbert
R. Small

2011 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

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

a) The distribution margin change of $62.2 million is mainly the result of the change in revenue derived from Enbridge Gas Distribution's IR framework and formula where forecast cumulative 2011 IR formula revenue was an increase of $76.9 million from the base year DRR amount (beginning amount in 2008 was $753.2, ending amount in 2011 was $830.1, EB-2010-0146 Rate Order Appendix A), increases in DSM and Customer Care related Y-Factors versus 2007 Board approved levels and, significant and partially offsetting lower required recoveries of carrying costs of gas in storage and working cash elements due to lower average gas commodity pricing within the 2011 QRAM's versus pricing embedded in 2007 approved rates. This results in a positive earnings impact.

b) The other revenue change of $6.3 million is due to increased late payment penalty revenue of $5.2 million, an increase in service charges of $1.9 million and a decrease in other revenue of $(0.8) million. This results in a positive earnings impact.

c) The other income change of $0.6 million is mainly due to revenue from the management of fee for service external 3rd party energy efficiency initiatives. This results in a positive impact on earnings.

Witnesses: K. Culbert
R. Small

d) Utility O&M is $34.3 million above that of the 2007 approved level embedded in base rates used within the incentive regulation escalation formula. For a visual of the details of utility O&M please see evidence at Exhibit B, Tab 4, Schedule 2. This results in a reduction in earnings.

e) The increase in depreciation expense of $49.3 million is due to higher levels of property, plant, and equipment associated within customer growth and system improvement activities in each of 2008, 2009, 2010, and 2011, and the implementation of the new CIS system in 2009. The impact of increases in customer growth and system improvement P.P.& E. in 2008, 2009 and 2010 has a full year depreciation increase impact in 2011 while the increases relative to 2011 have a part year depreciation increase impact. The depreciation increases result in a reduction in earnings.

f) Other expense increases of $6.6 million are the result of, an increase in recognition of EGD's $22.3 million share of the IR agreement tax savings impact, an increase in fixed financing and debt redemption premium costs of $1.8 million, a decrease from the elimination of the notional utility account amounts versus the 2007 approved level of $9.2 million, and decreases in municipal and capital tax of approximately $8.3 million mostly the result of decreased capital tax rates as recognized in the IR tax savings agreement. The net result is a reduction in earnings.

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

h) The interest cost of utility long, medium and short term debt and preference share costs changed by $26.9 million relative to 2007 approved levels as a result of lower overall average cost rates. This results in a positive earnings impact.

Witnesses: K. Culbert
R. Small

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2011 HISTORICAL YEAR

		Col. 1	Col. 2	Col. 3	Col. 4
Line no.		Audited Consolidated Income ($millions)	Utility Income ($millions)	Difference ($millions)	Reference
1.	Gas commodity and distribution revenue	2,010.2	1,978.4	(31.8)	a)
2.	Transportation of gas for customers	352.1	411.2	59.1	b)
3.		2,362.3	2,389.6	27.3	
4.	Gas commodity and distribution costs	1,341.7	1,383.7	42.0	c)
5.	Gas distribution margin	1,020.6	1,005.9	(14.7)	
6.	Other revenue	104.4	42.9	(61.5)	d)
7.		1,125.0	1,048.8	(76.2)	
	Expenses				
8.	Operation and maintenance	418.8	360.5	(58.3)	e)
9.	Earnings sharing	13.0	-	(13.0)	f)
10.	Depreciation	281.0	276.6	(4.4)	g)
11.	Municipal and other taxes	40.5	37.6	(2.9)	h)
12.	Company share of IR agreement tax savings	-	22.3	22.3	i)
13.		753.3	697.0	(56.3)	
14.	Income before undernoted items	371.7	351.8	(19.9)	
15.	Financing income	62.7	-	(62.7)	j)
16.	Interest and financing expenses	(172.4)	(3.1)	169.3	k)
17.	Income before income taxes	262.0	348.7	86.7	
18.	Income taxes	50.7	57.0	6.3	l)
19.	Net Income	211.3	291.7	80.4	

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2011
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	2,010.2	**Consolidated gas commodity and distribution revenue**
	(32.3)	Amounts related to St. Lawrence Gas
	(1.1)	Normalization adjustment
	1.4	Gazifere T-service regrouped to gas commodity and distribution revenue
	0.2	Remove adjustment relating to the updated tax saving sharing agreement included in the 2011 financials, but already reflected in the 2010 ESM calculation
	1,978.4	**Utility gas commodity and distribution revenue**
b)	352.1	**Consolidated transportation of gas for customers**
	(6.9)	Amounts related to St. Lawrence Gas
	(1.4)	Normalization adjustment
	(1.4)	Gazifere T-service regrouped to gas commodity and distribution revenue
	68.8	Western T-Service Credits regrouped to gas costs
	411.2	**Utility transportation of gas for customers**
c)	1,341.7	**Consolidated gas commodity and distribution costs**
	(25.7)	Elimination of amounts related to St. Lawrence Gas and unregulated storage
	(1.1)	Normalization adjustment
	68.8	Western T-Service Credits regrouped to gas costs
	1,383.7	**Utility gas commodity and distribution costs**

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2011
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	104.4	**Consolidated other revenue**
	(21.5)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects
	(13.6)	Open Bill O&M expenses regrouped against program revenues
	(5.1)	ABC administration and bad debt costs regrouped against program revenues from O&M
	(0.1)	ABC interest charges regrouped against program revenues
	5.2	Allowable interest during construction regrouped to revenues from interest and financing expenses
	(7.3)	Electric CDM costs regrouped against program revenues from O&M
	0.1	NGV program revenue imputation
	(4.4)	Elimination of transactional services revenue above base amount included in rates
	0.2	Elimination of the shareholder portion of the OBSDA and OBAVA write-off
	(0.2)	Elimination of the shareholder portion of net ex-franchise Open Bill revenues
	(1.6)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(0.3)	Elimination of the shareholder portion of net electric CDM revenues
	(1.3)	Elimination of affiliate and 3rd party asset use revenue considered non-utility
	(5.9)	Elimination of net ABC revenue considered non-utility
	(0.5)	Elimination of interest income from investments not included in rate base
	(5.2)	Elimination of allowable interest during construction
	42.9	**Utility other revenue**
e)	418.8	**Consolidated operation and maintenance**
	(11.5)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects
	(13.6)	Open Bill expenses regrouped against program revenues
	(5.1)	ABC administration and bad debt costs regrouped against program revenues and eliminated
	(7.3)	Electric CDM expenses regrouped against program revenues
	1.0	Interest on security deposits added to utility O&M
	(3.0)	Elimination of donations
	(1.8)	Elimination of non-utility costs of supporting the ABC program
	(16.7)	Elimination of Corporate Cost Allocations above RCAM amount
	(0.1)	Elimination of non-utility green energy costs
	(0.2)	Incremental unregulated storage allocation resulting from the incorporation of the B&V Study
	360.5	**Utility operation and maintenance**
f)	13.0	**Consolidated earnings sharing**
	(13.0)	Elimination of earnings sharing amounts within year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	281.0	**Consolidated depreciation**
	(3.9)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects
	(0.2)	Elimination of depreciation on disallowed Mississauga Southern Link
	(0.3)	Elimination of depreciation related to shared assets
	276.6	**Utility depreciation**

Witnesses: K. Culbert
R. Small

RECONCILIATION OF 2011
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	40.5	**Consolidated municipal and other taxes**
	(1.7)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects
	(0.2)	Elimination of municipal taxes related to shared assets
	(1.0)	Adjustment to convert capital taxes to a utility "stand-alone" basis
	37.6	**Utility municipal and other taxes**
i)	-	**Consolidated IR agreement tax savings**
	22.3	Recognition of the Company's share of IR agreement tax savings, as determined in EB-2007-0615, and updated in EB-2009-0172, EB-2010-0146, and EB-2011-0008.
	22.3	**Utility IR agreement tax savings**
j)	62.7	**Consolidated financing income**
	(62.7)	Eliminate non-utility dividend income from the Board Approved financing transaction
	-	**Utility financing income**
k)	172.4	**Consolidated interest and financing expenses**
	(2.5)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects
	(26.8)	Eliminate non-utility interest expense from the Board Approved financing transaction
	5.2	Allowable interest during construction regrouped to revenues and eliminated
	(0.1)	ABC interest charges regrouped against program revenues and eliminated
	(145.1)	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure
	3.1	**Utility interest and financing expenses**
l)	50.7	**Consolidated income taxes**
	(3.8)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas, and solar projects
	(46.9)	Elimination of corporate income taxes
	57.0	Addition of income taxes calculated on a utility "stand-alone" basis
	57.0	**Utility income taxes**

Witnesses: K. Culbert
R. Small

ALLOCATION OF COSTS
REGULATED AND UNREGULATED STORAGE ACTIVITIES

1. During 2011, Enbridge Gas Distribution has conducted both regulated and unregulated storage activities from within the integrated storage facilities that it owns in Lambton and Kent Counties. Enbridge allocated capital and O&M costs between the regulated and unregulated storage businesses in 2011 using methods similar to those that were employed in 2010. The generalities of those methods were presented to the Board and discussed in last year's evidence (EB-2011-0008, Exhibit B, Tab 1, Schedule 6).

2. In the Settlement Agreement for EB-2011-0008, the parties agreed that in future proceedings Enbridge would provide further information regarding its methods for allocating costs between its regulated and unregulated storage operations. Specifically, in part s, item 3 of the Agreement, the parties agreed that:

> For the purpose of reaching an overall settlement, no party opposes Enbridge's allocation of costs between regulated and unregulated storage activities for the purpose of determining the 2010 ESMDA amount. There is no agreement as to whether Enbridge's continued use of its current approach to allocating costs between regulated and unregulated storage is appropriate for future years. Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study, prepared by an external expert, evaluating the appropriateness of the allocation of costs between Enbridge's regulated and unregulated storage activities. It is expected that the expert will provide a professional assessment of the methodologies used and recommendations for alternate approaches if, in their opinion, improvements can be made.

3. As a result of that request Enbridge solicited a Request for Proposal for such a review from a number of consultants. Subsequent to that exercise, it selected and retained the services of the Black & Veatch Corporation ("Black & Veatch") to conduct the review.

Witnesses: K. Culbert
B. Pilon

4. In the course of the preliminary discussions with Black & Veatch, Enbridge provided them with a copy of a discussion paper that offered an overview of its storage operations as they were prior to the timing of the Natural Gas Electricity Interface Review ("NGEIR"), as well as the capacity development work that the Company had completed since then. This document also provided a synopsis of the methodologies that Enbridge had come to use in determining the sharing of the various capital and operating costs of the gas storage operation between the regulated and unregulated storage businesses. A copy of that discussion paper is attached here as Exhibit B, Tab 1, Schedule 5, Appendix I.

5. Though the Black & Veatch review commenced in the fall of 2011, the final report was not available until May of 2012. While Black & Veatch has recommended some changes to Enbridge's methodologies, those recommendations (which had not been made as of 2011 year-end) were not reflected in the cost allocation methods or in the resulting cost allocations booked for 2011. As a result, the cost allocation methods employed in 2011, for the purposes of determining the year-end allocation of storage costs to be used for the ESM calculation, were the same as those used in 2010.

6. The resulting allocation of O&M costs for 2011 is presented below in Exhibit B, Tab 1, Schedule 5, Appendix II. This table, both in its form and in the underlying cost sharing method, is similar to what the Board has seen for 2010 and in earlier years. It shows the year over year operating capacities that have been available to the two businesses since 2007 as well as the resulting amounts of O&M costs that have been borne by each.

Witnesses: K. Culbert
B. Pilon

7. In addition to the 2011 cost sharing summary shown in this table, the Company has also included a representative sample of one set of the monthly O&M cost allocation worksheets for that year. Again, these worksheets illustrate the cost sharing principles and calculations that Enbridge has been using since late 2009. These worksheets can be found as Exhibit B, Tab 1, Schedule 5, Appendix III.

8. As discussed in paragraph 2 above, the Black & Veatch study report is intended to inform the Board in its review of the Company's 2013 rate application. However, as much of the focus of the review was based upon the 2011 storage operating costs, Enbridge felt that it would be appropriate to file a copy of the report as part of the evidence for this proceeding. That report can be found at Exhibit D2, Tab 5, Schedule 1**.**

9. The Black & Veatch report makes several recommendations for changes to Enbridge's storage cost allocation methodology and documentation. As described in that report, Enbridge has reconsidered some of its cost allocation methods and taken it upon itself to proactively accept and implement each of the recommendations that Black & Veatch has made.

10. The most notable of the accepted recommendations is the suggested use of a storage withdrawal or deliverability element as the basis for some of the fixed O&M cost sharing. For 2011 and prior years, only storage capacity 'in the ground' has been used as the basis for sharing those O&M costs that are seen as relatively fixed. Although the Black & Veatch report has been available for only a short time, Enbridge has moved to incorporate this new element into its proposed cost allocations for 2012, and to re-cast its 2011 storage cost allocation calculations using this approach.

11. Exhibit B, Tab 1, Schedule 5, Appendix IV is an example of the revised monthly O&M cost allocation worksheets for 2011 that have been developed with a deliverability component incorporated into them. For comparative purposes this is for the same month as presented in Exhibit B, Tab 1, Schedule 5, Appendix 3.

12. Enbridge has looked at the 2011 O&M cost sharing that would have resulted had it been using this revised methodology. The resulting allocated amount would have been about $1.6 million or about 15 percent higher than the $1.4 million that had been allocated using the current methodology. Exhibit B, Tab 1, Schedule 5, Appendix V shows a month by month comparison of those amounts.

13. As noted, Enbridge has decided that it will adopt and apply Black & Veatch's recommendations in relation to the methodology to use for calculating the allocation of costs between regulated and unregulated storage operations. To reflect this decision, Enbridge has updated its 2011 O&M cost sharing, using the amounts described in the paragraph above. The results of this update have been incorporated in the documents filed as Exhibit B, Tab 1, Schedules 1 and 2, which set out the updated ESM amount for which Enbridge is seeking approval in this proceeding.

Enbridge Storage Cost Allocation

As part of the 2011 ESM Settlement Agreement, Enbridge Gas Distribution Inc. (Enbridge) agreed to engage an independent third party consultant to review the methods by which Enbridge's costs are shared and allocated between its regulated and unregulated storage activities. The consultant is also to provide comments on the appropriateness of the allocation methodology and suggest alternatives or changes in the event that they might feel that improvements could be made. The results of this study are to be filed with Enbridge's evidence in support of its 2013 rate application.

In view of this commitment, and to facilitate the consultant's review, Enbridge has created this document to provide the third party with a general understanding of its storage facilities and their operation. It also identifies the various costs, both capital and operating, that relate to Enbridge's storage operations and explains the methods that underlie its current cost allocations.

I. ***Background***

A. NGEIR Decision

One of the key goals of NGEIR was to examine how new storage and other services could be developed to meet the needs of gas fired generators.

In the NGEIR Decision (EB-2005-0551, November 7, 2006), the Ontario Energy Board (OEB, or the Board) determined that the market for ex-franchise and new storage services is competitive, and concluded that it will not regulate the prices charged by gas distributors for these services. The Board's expectation was that such an approach would encourage the rational development of new storage services and capacity.

As a result, Enbridge was permitted to develop new storage services within the competitive market, such that the utility, and not ratepayers, would bear the risk and enjoy the benefits of these investments. The Board would not regulate the rates and revenues for this newly developed storage.

As part of the NGEIR Decision, the Board agreed that there would be no need to functionally separate Enbridge's regulated and un-regulated storage activities and recognized that Enbridge would use these integrated storage facilities to provide both regulated and un-regulated storage services.

B. Enbridge's Regulated Storage Activities Prior to 2007

At the time of the NGEIR Decision, Enbridge owned approximately 91.3 Bcf of working storage capacity in Lambton/Kent with maximum daily withdrawal capability of about 1.74 Bcf. All of this capacity was committed to Enbridge's in-franchise customers. Enbridge was also operating a small storage pool in the Niagara Region (Crowland) with a storage capacity of about 0.39 Bcf. Because of the location and size of this storage facility, most of this discussion will be focused on the Lambton/Kent operations.

In addition to the in-franchise services, Enbridge was also providing a smaller amount of ex-franchise storage service. Capacity was contracted to Niagara Gas Transmission Ltd. (NGTL), allowing it to deliver gas into Enbridge's storage system and take custody of it at the Dawn Hub at a maximum rate of 0.08 Bcf/d. Enbridge also operated approximately 6.7 Bcf of storage capacity, with 0.11 Bcf of daily withdrawal capability, under contract with Union Gas Limited (Union). Those capacities accommodated the needs for two of Union's storage pools, the Dow Moore and Black Creek pools.

Both Union and NGTL had the upstream facilities to deliver gas into Enbridge's storage system but had to rely upon Enbridge's storage facilities, and its operation, to move that gas to the required custody points. Neither party had contributed to the cost of the facilities used to move gas within Enbridge's storage system, and so they pay a cost-based rate to Enbridge for that service.

In addition to these long term in-franchise and contracted services that were in place at the time of the NGEIR Decision, Enbridge was also able to sell any available short term storage capacity to further optimize the use of its storage assets, through Transactional Services (TS) activities. Through TS activities, Enbridge was able to further leverage its storage assets and capacities for the benefit of both its utility customers and its shareholders. By selling these temporarily available capacities, Enbridge was able to obtain additional revenue, which was shared between ratepayers and Enbridge's shareholders. As a result, its customers have enjoyed a lower cost of service and its shareholders; higher earnings.

The gross value of Enbridge's regulated storage assets in 2007 was $261 million or about $175 million net of some $86 million of accumulated depreciation.

II. *Enbridge Storage Since 2007*

Since the date of the NGEIR Decision, Enbridge has added new storage capacities to its operations. Consistent with the NGEIR Decision, those new storage capacities are not part of Enbridge's regulated storage operations. A more detailed discussion of Enbridge's unregulated storage activities is described below.

During this time, Enbridge has also continued to operate its regulated storage operations in the same manner as it had before the NGEIR Decision. Those operations are discussed below as well.

A. Regulated Storage Activities

There have been no changes in either the working volume capacity or injection/withdrawal capacities that are available to Enbridge's utility customers, since 2007. They still have access to the 91.3 Bcf of storage capacity with the maximum daily withdrawal capability of 1.74 Bcf. Similarly, Union and NGTL still have access to the same levels of services that they had prior to 2007.

There has been no erosion in the level of TS activity that is possible; excess capacities that are part of the 91.3 Bcf of regulated storage capacity are still available and used to provide for TS activities. The level of actual TS activity can fluctuate, for a number of reasons, but there has been no reduction in the potential for it to occur as a result of the development of un-regulated storage services.

These regulated storage activities continue to drive the need for, and cost of, ongoing capital projects and operations and maintenance (O&M) expenses.

The capital costs relate largely to the 'maintenance' capital that is required to replace or recondition equipment that, through age, use or obsolescence, has come to the end of its useful life. In addition to these types of projects, Enbridge must also continue to undertake the capital projects that are necessary to ensure the continued environmental, safety and technical compliance of its regulated gas storage facilities, as would be expected of any good operator. These would include such recent projects as the noise and exhaust emission improvements being made to its compressor plants, as required by the MOE, and the enhancements in its gas measurement and gas inventory observation facilities, as requested by the Company's management and auditors.

Table 1 shows the year over year comparison of the regulated storage rate base from 2007 through 2011. It clearly shows the impact of some of the above mentioned initiatives.

Table 1

ENBRIDGE GAS STORAGE - REGULATED STORAGE ASSETS
Net Property,Plant & Equipment
Year end Balance
($ millions)

Asset	2007	2008	2009	2010	2011
Land & Land Rights (450/451)	22.5	21.4	20.4	21.1	20.2
Structures & Improvements (452.00)	6.5	6.5	6.5	9.6	9.5
Wells (453.00)	12.4	12.4	13.4	20.7	22.5
Well Equipment (454.00)	3.8	4.0	4.3	4.6	4.3
Field Lines (455.00)	27.6	26.8	26.7	25.9	38.4
Compressor Equipment (456.00)	54.3	56.7	59.4	60.8	61.5
Measuring and Regulating Equipment (457.00)	7.3	7.0	6.8	6.6	6.2
Base Pressure Gas (458.00)	40.8	40.8	40.8	40.9	40.9
Totals	$ 175.2	$ 175.6	$ 178.3	$ 190.2	$ 203.5

Storage Capacities

	2007	2008	2009	2010	2011
ATV (Bcf)					
In Franchise	91.3	91.3	91.3	91.3	91.3
Ex Franchise	6.7	6.7	6.7	6.7	6.7
Total	98.0	98.0	98.0	98.0	98.0
Withdrawal Capacity (MMcfd)					
In Franchise	1.74	1.74	1.74	1.74	1.74
Ex Franchise	0.19	0.19	0.19	0.19	0.19
Total	1.93	1.93	1.93	1.93	1.93

The O&M costs associated with Enbridge's regulated storage operations have remained relatively constant over the years since 2007. Table 2 shows the year over year comparison of the O&M costs associated with Enbridge's regulated storage operations from 2007 through 2011.

Table 2

ENBRIDGE GAS STORAGE - REGULATED O&M
Includes Property Taxes
($s)

Summary of Expenses	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual
OPERATING EXPENSE					
LABOUR	1,171,752	1,271,254	933,880	963,876	1,360,134
SUPPLIES & OTHER	548,120	672,325	612,797	775,696	746,614
ENVIRONMENTAL	35,896	57,439	26,468	37,278	18,369
SAFETY	82,410	55,541	91,181	72,652	111,640
LABOUR & O&M CREDITS	(89,344)	(223,017)	(160,046)	(246,502)	(484,019)
TOTAL OPERATING EXPENSE	**1,748,834**	**1,833,542**	**1,504,280**	**1,603,000**	**1,752,738**
PLANT MAINTENANCE EXPENSE					
LABOUR	590,938	679,471	946,683	1,114,251	930,017
MATERIALS	463,819	473,506	392,241	559,669	573,679
CONTRACTOR LABOUR & MATERIALS	620,122	471,112	584,986	623,497	546,481
LABOUR & O&M CREDITS	(129,853)	(222,175)	(349,639)	(409,025)	(454,734)
TOTAL PLANT MAINTENANCE	**1,545,026**	**1,401,914**	**1,574,271**	**1,888,392**	**1,595,443**
FIELD MAINTENANCE EXPENSE					
MATERIALS & SUPPLIES	49,126	6,592	17,061	12,934	44,786
CONSULTING	45,138	154,596	126,044	128,327	31,601
ENVIRONMENTAL	-	100	-	17,676	34,762
CONTRACT SERVICES	814,826	790,857	755,610	1,394,562	897,552
OTHER OUTSIDE SERVICES	-	-	1,565	-	7,167
LABOUR & O&M CREDITS	-	(829)	(31,666)	(58,680)	(128,200)
TOTAL FIELD MAINTENANCE EXPENSE	**909,090**	**951,316**	**868,614**	**1,494,819**	**887,668**
ADMIN & GENERAL EXPENSE					
LABOUR	1,526,985	1,548,744	1,649,360	1,677,224	1,918,444
LEASE RENTALS	1,334,490	1,341,487	1,500,232	1,588,118	1,213,846
OTHER	568,580	569,266	561,154	827,653	849,047
LABOUR & O&M CREDITS	(825,019)	(833,354)	(858,705)	(1,322,443)	(1,292,011)
TOTAL ADMIN & GENERAL	**2,605,036**	**2,626,143**	**2,852,041**	**2,770,552**	**2,689,326**
CROWLAND EXPENSE					
LABOUR	71,576	75,302	77,330	79,665	91,003
LEASE RENTALS	31,766	34,721	46,592	39,225	36,884
OTHER	261,292	164,555	275,707	70,486	90,982
LABOUR & O&M CREDITS	-	-	-	-	-
TOTAL CROWLAND EXPENSE	**364,634**	**274,578**	**399,629**	**189,376**	**218,869**
NET OPERATING, MAINTENANCE & A&G	**7,172,620**	**7,087,493**	**7,198,835**	**7,946,139**	**7,144,044**
PROPERTY TAX					
TECUMSEH	1,256,895	1,115,734	1,264,584	1,358,820	1,544,472
CROWLAND	64,665	65,199	66,768	66,888	66,768
TOTAL PROPERTY TAX	**1,321,560**	**1,180,933**	**1,331,352**	**1,425,708**	**1,611,240**
TOTAL REGULATED STORAGE	**8,494,180**	**8,268,426**	**8,530,187**	**9,371,847**	**8,755,284**

B. Un-regulated Storage Activities

After the NGEIR Decision, Enbridge took steps to identify and develop the storage facilities that would be required to serve the needs of the market, including those of gas-fired electricity generators. As explained in the course of the NGEIR proceeding, this was to be done, largely, by making investments in Enbridge's existing storage system, to add the capacity and deliverability beyond what then existed.

In 2007, Enbridge began some of the capital projects that were required to create the new, un-regulated storage capacities. Since that time Enbridge has initiated a total of four capital programs intended to develop these incremental capacities at a total cost of $87 million dollars.

These programs have included the drilling of additional wells into the storage pools and the installation of additional pipelines, compression, gas dehydration and measurement capacity. Some of the additional metering capacity has been added at the custody transfer point into the Union Gas transmission system at Dawn, but some has also been created at a new custody point into the Vector pipeline system.

As a result of these capital programs, Enbridge has created the new storage capacities that it has offered to the market. In total, these projects have resulted in the development of 12 Bcf of total storage capacity and incremental withdrawal capability of some 400 MMcfd to the end of 2011. Without these capital investments, none of the new storage capacities would exist.

Table 3 below provides a year over year comparison of the accumulated cost of these capital projects. It shows the type of assets that have been added, as well as the growing levels of the un-regulated storage capacities, as they have occurred. Those capacities are normally made available in early spring.

Table 3

ENBRIDGE GAS STORAGE - UNREGULATED GAS STORAGE ASSETS
Net Property,Plant & Equipment
Year end Balance
($ millions)

Asset	2007	2008	2009	2010	2011
Land & Land Rights (450/451)	-	-	0.4	1.1	1.1
Structures & Improvements (452)	-	-	-	-	-
Wells (453)	-	3.9	7.2	10.0	9.6
Field Lines (455)	1.3	8.5	14.6	14.6	14.2
Compressor Equipment (456)	7.0	9.9	11.9	20.1	20.6
Measuring and Regulating Equipment (457)	-	-	0.4	0.3	0.3
Plant not classified	-	14.2	12.9	3.6	38.6
Totals	8.4	36.4	47.3	49.7	84.4
ATV (Bcf)	0.0	2.2	4.2	8.7	12.2
Withdrawal Capability (MMcfd)	0	157	269	359	401

The O&M costs associated with the operation of this unregulated storage have also grown over the years since 2007. They include the allocated O&M cost from the operation of the integrated storage facilities and those costs that are specific to the unregulated storage business.

The costs that are specific or directly attributable to the unregulated business include that for dedicated staff, Enbridge Gas Control services from Edmonton, corporate A&G overheads that are charged directly to unregulated storage, and a host of professional services such as legal, engineering and financial. These activities and their costs are not a part of the integrated gas storage operations and are charged entirely to unregulated storage.

There is a summary of these, year over year, costs shown on Table 4 below.

C. Operation of the Integrated Storage Facilities

The combined regulated and unregulated storage assets are operated by Enbridge's storage group as one integrated system. That is consistent with the Board's findings in the NGEIR Decision.

The storage service nominations of all customers, both regulated and un-regulated, are aggregated by Enbridge's Gas Control group in Edmonton and one total nomination, or quota, is made to Storage Operations for the volumes required at each custody point. Gas Control ensures that all of the individual nominations are within the contract terms of each customer.

Storage Operations, then, sets up and optimizes the use of the integrated system to meet these total aggregated nominations for each day, while ensuring that the system capability, at the end of the day, is best able to meet the expected longer term needs of all of its customers. On any day, the storage group does not know what the component makeup is of the requested nominations, and simply operates the integrated storage facilities in the best way that it can to accommodate those nominated volumes.

From an accounting perspective, however, the regulated and un-regulated businesses are kept separate so as to ensure that both are carrying their share of the costs. That is also consistent with the Board's findings in the NGEIR Decision.

All of the capital costs that have been incurred to create the un-regulated storage capacities are carried on the books of the un-regulated storage business. Similarly, an appropriate amount of the total cost of operating the integrated system is also charged to the un-regulated business. Details of the principles underlying this cost allocation approach, and the results of it, are set out below.

D. Benefits of Unregulated Storage Development for Regulated Customers

Before moving on to explain how Enbridge allocates costs between its regulated and unregulated storage operations, it is important to highlight some of the benefits that the regulated storage operations and customers enjoy as a result of the addition of the unregulated storage facilities to Enbridge's integrated storage system. No amounts are charged to, or paid by, Enbridge's in-franchise storage customers in relation to these benefits.

Among these benefits are:

1. **Added storage reliability**
   The un-regulated storage assets (which are not part of utility rate base) have created new delivery points and the associated infrastructure in which to move gas. This diversity reduces the overall system dependence on the pre-NGEIR facilities and provides operating alternatives in the event of either a planned, or un-planned, outage of some of those facilities.

   In addition, many of the pre-NGEIR assets have been reinforced or replaced with new, higher pressure rated assets. As a result, the system is generally more reliable than it was before.

   Also, in the event of an equipment failure or outage, any remaining capacities will be pro-rated amongst all of Enbridge's customers, both regulated and unregulated. In that way, utility customers will have more reliable access to capacity and, should the unregulated storage business' customers not require their shares, the utility would have even more than their pro-rata share.

2. **Added storage flexibility**
   The existence of these new assets also offers Enbridge more ways in which it may operate its storage facilities for its utility customers. As an example, the new delivery points, and their associated capacities, can be used by the utility and will allow it a broader choice of up and downstream service alternatives than it had access to previously. As a result, the utility can a broader array of gas and related transportation services.

3. **Reduced cost of service**
   Some of the capital additions of the un-regulated storage business have resulted in the replacement, and retirement, of some regulated assets (pipelines, wellheads). These retirements have, and will, serve to reduce the amount of regulated rate base, and to eliminate the associated return requirement that is carried by utility customers.

   With the retirement of these regulated assets, the amount of capital depreciation expense being carried by the utility has also been reduced.

   As well, some of the new operating flexibilities, discussed above, have already allowed the utility to avoid some higher cost, upstream and downstream service options such as gas backhauls and gas dehydration. The utility savings from these kinds of options are not inconsequential.

   And finally, the total O&M costs of the integrated storage operation are shared between the regulated and unregulated businesses on the basis of capacity and not on incremental cost causation. As most storage O&M costs are not increasing in proportion to the level of the capacity adds, the sharing results in a proportionately lower cost to the utility storage customers than they might otherwise have experienced. Similarly, where there are cost pressures that are not driven by changes in capacity or activity, some of those costs are also being shared by the unregulated business. Changing technical and environmental standards are examples of these.

III. *Cost Allocation Philosophy*

In the NGEIR Decision, the Board recognized that all of Enbridge's then-existing storage assets were required to serve in-franchise customers. The Board agreed that Enbridge could develop new storage capacities to serve both in-franchise and ex-franchise customers, and that the Board would not regulate the prices for any of the new storage services developed and offered.

In the NGEIR Decision, the Board found that, in the event that Enbridge developed new (unregulated) storage, it would not be necessary for it to functionally separate its regulated and unregulated storage operations. That is, the newly created capacities could operate from within one integrated system. However, a requirement of the NGEIR Decision, for participation in the un-regulated storage industry, was that Enbridge would create a separate set of books in which to keep the accounts for this activity. Enbridge has done this and these books accommodate all of the costs associated with the development and operation of unregulated storage capacity, both capital and O&M, as well as the cost of allocated overheads, fuel and lost and unaccounted for gas volumes.

In addition, as Enbridge's regulated and unregulated storage operations would be integrated, it was incumbent upon Enbridge to determine an appropriate method of allocating costs between them. In determining what costs are allocated to regulated and unregulated storage operations, the key question asked is "Which operation has caused the costs to be incurred?"

For capital projects, this question leads to a straight-forward allocation practice. Capital projects for gas storage can normally be classified as those that provide incremental capacity, those that replace existing assets, like-for-like, and those that replace assets but also provide additional capacity. There are also general plant projects that are not specific to either business. The allocation of costs will vary for each of these types of assets, based upon which operation has "caused the costs to be incurred".

For O&M costs, however, this question was not as helpful in guiding the allocation practice. Certainly if costs were being driven exclusively by either of the operations, then that operation would be expected to pay those costs. The difficulty, however, was that it was not always easy to determine how much of the cost was attributable to each operation. As a result, most O&M costs are allocated and shared on the basis of the relative proportions of the total storage capacities and, in some cases, storage activity of the regulated and unregulated businesses.

By applying this philosophy, each of the regulated and unregulated storage operations is allocated the costs that relate to its operations and related service capacities. The result is a simple and transparent approach that fairly allocates costs.

Enbridge has used the above described cost allocation philosophy since the inception of its un-regulated storage business.

A. Overall cost allocation results over the years from 2007 to 2011

The application of Enbridge's cost allocation philosophy has resulted in Enbridge's regulated and unregulated storage operations paying the appropriate share of the overall storage costs.

In terms of capital costs, the amounts allocated to each of regulated and unregulated operations can be seen in Tables 1 and 3 above. As can be seen in those charts, the overall rate base amount associated with the regulated storage operations has shown little change over the 2007 to 2011 period, other than for the costs associated with the measurement and inventory enhancement work, while the corresponding unregulated storage net capital has grown from $8.4 to $87 million. A more detailed discussion of how new capital spending is allocated between regulated and unregulated operations, is set out in Section B below.

In terms of O&M costs, Table 4 below shows the storage capacity and O&M costs that relate to each of the unregulated and regulated storage operations from 2007 to present.

Table 4

ENBRIDGE GAS STORAGE
Capacity and Cost Sharing
Regulated and Unregulated Storage

		2007	2008	2009	2010	2011
Unregulated Storage Capacity as of April 1 (Bcf)		-	3.0	5.5	7.5	12.2
Regulated Storage Capacity (Bcf)		98.0	98.0	98.0	98.0	98.4
Total Storage Capacity		98.0	101.0	103.5	105.5	110.6
	($ millions)					
Direct Unregulated Storage O&M		0.24	0.30	0.78	0.77	0.56
Allocated Storage	- Labour & Overheads	-	0.03	0.10	0.25	0.57
	- Operations & Maintenance	-	0.01	0.11	0.21	0.42
	- Administration & General	-	0.01	0.13	0.23	0.42
Total Unregulated Storage O&M		0.24	0.35	1.12	1.46	1.96
O&M Allocated to Unregulated		-	0.05	0.34	0.69	1.40
O&M Regulated Storage		8.45	8.22	8.56	9.26	8.96
Total O&M for Storage		8.45	8.27	8.90	9.95	10.36

Property taxes are included in above numbers

It should be noted that the increase in the Regulated Storage Capacity figures shown in the second line of Table 4, for 2011 reflects the inclusion of the Crowland capacity. The O&M costs associated with the Crowland operation are included in the cost summary.

B. Storage Capital Project Costs

As explained earlier, in the years following the NGEIR Decision, Enbridge has initiated a number of capital projects intended to develop the additional storage capacities and services required by gas fired electrical generation customers, as well as others. The costs of these projects have been charged to the books of the unregulated storage business.

The Company has also continued to conduct the capital work that is required to maintain and update the storage plant that underlies the 91 Bcf of traditional storage service provided for in-franchise customers. The costs of these projects, like the cost of the original utility storage assets, are charged to the accounts of the regulated storage business.

As the Company proceeds with the construction of the capital projects that are required of both the utility and unregulated storage businesses, it is necessary that the Company use a consistent criteria and practice by which to determine the appropriate amount of capital costs that should be charged to each business. As the unregulated storage operations grow and evolve, it will be increasingly important to ensure that this criteria and practice are transparent, fair and relatively easy to apply.

Those practices will have to provide a clear and consistent means by which to determine the accounting treatment for the following type of capital projects:

- Replacement of Assets
- Development of Incremental Storage Capacity
- Replacement of Assets with a Capacity Enhancement Component
- General Storage Plant

The following describes the cost attribution and cost sharing fundamentals that Enbridge uses for its storage assets:

1. **Replacement of Assets:**

   For these projects this is a fairly simple exercise. For those ‘like for like’ asset replacement projects, it is clear that the project is intended to maintain the facilities and service capabilities that were required to serve Enbridge’s customers, regulated or unregulated. Whether it is the complete replacement of a particular asset, or the work required to recondition or bring an asset into compliance with a regulatory or corporate standard, the costs are charged to the accounts of the original asset.

2. **New Storage Capacity Development :**

   For those capacity development projects that are intended to provide new storage capacity or deliverability, it is clear that the project provides no direct benefit to the utility customers and so all of the costs are charged to the accounts of the unregulated storage business. Well drilling and compressor and pipeline installation projects of the unregulated business are examples of these types of projects.

3. Replacement of Assets with a Capacity Enhancement Component:

There may also be a number of possible scenarios where existing assets are replaced, but where the cost of the replacement assets would be shared between the regulated and unregulated storage businesses. As discussed on page 8, the allocation of costs in these scenarios will be driven by the particular circumstances behind the replacement.

For example, it may be necessary to replace a utility asset at the end of its useful life, but where the replacement asset is sized to provide additional capacity beyond that of the original asset, with that capacity available to the unregulated business. In such a scenario, the replacement of the asset has been driven by the fact that it is no longer technically capable of providing the service for which it was intended; the utility needs to replace it to maintain the level of storage service required.

As a result, the utility would carry the portion of the cost that it would have incurred if it were to have replaced the asset, like for like. And, on that basis, the unregulated business would be charged for the incremental costs that would have resulted from the higher capacity asset. This would include both the cost of the incremental capacity and, the cost of any of the system design changes that might have been required to accommodate the different asset. In this scenario, the portion of the total asset cost that will be booked to the utility will be no more than would have been incurred had the replacement asset been sized simply to replace the original. The replacements of compressor units or measurement equipment are examples of this type of scenario.

Another scenario might be that an unregulated asset requires replacement but with a capacity enhancement. Not surprisingly, this would result in all of the costs being charged to the unregulated business.

Conversely, in a scenario where the asset is not at the end of its useful life, but where its replacement is driven by the operational needs of the unregulated storage business, then the unregulated storage business would pay for all of the cost of the replacement, and not just a portion, based upon its share of the resulting capacity. And in this case the utility would enjoy not only the system benefits of the newer asset, but also that of seeing the removal of the original asset from rate base and the attendant reduction in the depreciation expense component of its cost of service. The replacement of pressure limited pipelines, wellheads and plant piping would be examples of such a replacement. The relative proportions of the replacement assets will be noted in the asset accounts of both businesses.

4. **General Storage Plant:**

   For general plant asset projects, such as office or utility buildings, Enbridge will determine the relative proportions of all general plant assets being carried by the regulated and unregulated storage operations. But, as it is in the other three scenarios, cost causation is still the key driver behind the allocation of these costs. If incremental, general plant assets are required by either business, then that direct need will be the primary basis for the cost allocation. If the project is driven more by the general needs of the integrated operation, then the cost will be allocated based upon capacity.

The costs associated with unregulated storage projects will include all of the materials and third party service costs that are incurred in the design, construction and commissioning of the facility. In most cases, the project will also require time and effort from Enbridge staff, with much of that being from Gas Storage personnel. In addition to these costs the project is also charged for interest during construction (IDC) and administration and general corporate overheads. The following speaks to each of those cost elements:

1. **Internal labour:**

   All staff working directly on the capital project keep time sheets that accumulate the time spent. Those time sheets are processed on a regular basis, and the time is charged at the hourly equivalent of the band rate for that employee.

2. **Corporate Administrative and General (A&G) Overheads:**

   Enbridge passes along corporate A&G costs to the unregulated business in the same manner as it does for O&M. The hourly salary rates for staff working on those projects are grossed up to include corporate A&G and also to include an amount associated with the expected performance based payout inherent in Enbridge's employee compensation. Together, these amounts result in an approximate 65 to 70% premium over the employee's base salary amount.

3. **Contractor and Materials:**

   All third party services and materials costs related to unregulated storage projects are charged to the un-regulated storage accounts.

4. **Interest During Construction (IDC):**

   Enbridge assesses an IDC charge to all unregulated storage projects in the same manner that it does for utility capital projects.

C. Operating and Maintenance Costs

With the commencement of unregulated storage operations, and the operation of the larger, integrated storage plant, total O&M costs have increased for the Company. There are more facilities to operate and maintain, and more gas volumes being handled.

Some specific O&M costs have increased, more or less in proportion to the increase in storage activity generally; however, others have increased only marginally or not at all. It is possible that the cost of some of these may increase with further growth of the unregulated storage services.

Recognizing the varying levels of O&M cost pressure experienced, Enbridge has instituted a cost sharing methodology that satisfies the guiding principles of transparency and fairness discussed above. It is essentially an 'across the board' allocation of all O&M costs based upon the relative proportions of the Company's total storage capacity and/or storage activity that is used by the unregulated and regulated businesses.

Included in this allocation are all direct and indirect costs of the storage operation such as operating O&M, corporate overheads, and fuel and lost-and-unaccounted-for (LUF) gas. Details of these are outlined below.

1. **Allocation of Storage Operations O&M (Tecumseh):**

   Enbridge allocates each of the O&M costs of the gas storage operation at an operating level of detail. The allocation approach is consistent with the fundamentals behind traditional cost of service analysis (functionalization, classification and allocation).

   For the purpose of these cost allocations between the two businesses, there has been no need to functionalize costs to either pools or compression. Costs have been classified between those that are relatively fixed, and do not vary with the levels of storage activity, and those that do vary with activity. This is essentially a split between demand and commodity costs.

   The classification splits are dependent upon the degree to which the particular cost is observed to vary with activity. If there would be little or no cost for a particular cost item, if there were no storage activity, then that cost would be classified as 100 percent variable. If a particular cost would not change, no matter what the level of actual storage activity, then that cost would be classified as 100 percent fixed. The Company has determined an item by item sharing of these, so classified, costs between the regulated and un-regulated businesses based upon their relative shares of the underlying storage capacities.

   The O&M costs that are deemed to be relatively fixed are shared between the two businesses based upon their relative shares of the total committed storage capacities. This means that, as the unregulated storage business grows, the unregulated business will be charged for an increasing share of these total storage system operating costs.

   Conversely, those O&M costs that vary with the levels of storage activity are shared using the actual costs incurred in each month, and the relative shares of the total actual storage activity of both the regulated and un-regulated businesses for that same month. In that way, the unregulated storage business, which may exhibit a more volatile activity profile than the more traditional usage of the utility customer, would pay a higher share of these variable costs in months when its customers require a lot of activity.

2. **Allocation of Corporate Administrative and General Overheads**:

   Enbridge allocates its A&G overheads to the unregulated storage business in the same way that it does for other services provided to unregulated activities. An hourly A&G overhead amount is determined for each full time equivalent staff member (FTE) and those costs are passed along as a premium to the hourly cost of FTEs involved in unregulated work.

   These overheads include a broad range of costs and services such as those for finance, regulatory, legal, HR and EH&S, as well as a return on, and the depreciation costs of, buildings and IT assets. The Company maintains a table whereby it allocates all of these budgeted costs and determines the amounts to be allocated to each full time staff member of the Company.

   In addition to these overheads, the allocation exercise also includes the expected cost of Enbridge's performance based pay incentive for storage operations' staff. The allocation of these overhead costs has the effect of increasing the base cost of labour by 65 to 70 percent.

   The calculation and inclusion of these amounts is an integral part of the monthly allocation exercise for storage operations O&M costs and is performed by the accounting staff at Tecumseh. The regular review and update of EGDI's fully allocated cost study is performed by the Finance group located in the Toronto offices of EGDI.

3. **Allocation of Unregulated Business Development and Administration Costs:**

   As a participant in the unregulated storage industry, Enbridge incurs other costs that are specific to the strategic development, management and operation of the business. These costs are charged directly to the set of accounts that are kept for the unregulated business. Among these is the cost of the dedicated management and staff of the unregulated storage business, the cost of Gas Control services in Edmonton and the cost of any professional services required, such as legal counsel and third party technical consultants.

   These resources are necessary to stay current with gas storage markets, identify storage service opportunities and their feasibility and to manage the contractual relationships that underlie the commercial basis for the un-regulated storage business. These costs are charged directly to the accounts of the unregulated storage business through the normal payroll, financial and A/P systems of Enbridge.

4. **Fuel Gas:**

   Since the commencement of unregulated gas storage services, Enbridge has charged the un-regulated storage operation for its proportionate share of the total cost of gas used for fuel in its storage operations at Tecumseh. The cost is calculated by pro-rating the actual monthly fuel volumes used in storage, based on the amounts of regulated and un-regulated storage activity in that month, and then charging for that volume using the previous October's QRAM reference price for gas. In this way both the un-regulated and regulated storage operations bear only their appropriate share of the cost of fuel gas used.

These fuel costs are assessed and charged by the Gas Supply group in Toronto.

5. **Lost and Unaccounted For Gas**:

Similar to its need to pay the cost of fuel gas used for un-regulated gas storage operations, the un-regulated business must also ensure that it provides its fair share of the gas volumes that are required to replace the Lost and Unaccounted for (LUF) gas volumes that are deemed to result from its storage activities. The un-regulated storage operation charges its customers for an 'in-kind' LUF volume based upon their respective storage capacities and activity.

The in-kind charge uses the same LUF replacement factor that underlies the current LUF replacement volume purchase allowed by the Ontario Energy Board.

IV. *O&M Cost Allocation Results for 2010 and 2011*

In order to illustrate how Enbridge applies its cost allocation philosophy, the Company has attached copies of the worksheets used to determine the allocation of O&M costs to each of the regulated and unregulated businesses. The attached worksheets cover all of 2010 and 10 months of 2011.

The O&M worksheets are prepared on a monthly basis, to determine the allocation of O&M costs on the basis of the relative shares of capacity and the relative levels of activity of the regulated and unregulated storage businesses. The sum totals of these monthly worksheets are consistent with the amounts set out in Tables 2 and 4.

Two items, however, are not included in the cost allocation results for 2010 and 2011.

First, there is no allocation of costs related to unregulated storage transactional services activities. That is because, to date, Enbridge has not attributed any of it TS activity or revenues to its unregulated storage business. All TS services to date have been deemed to have been conducted as part of the regulated storage operations, and subject to the 90/10 revenue sharing practice as set out in the NGEIR Decision.

Enbridge notes that, despite its practice so far, as it continues to develop additional unregulated capacities, it may choose to commence TS activities from within the capacities of the unregulated storage business. If that occurs, the Company will adopt an appropriate method of allocating TS revenues between the regulated and unregulated businesses, consistent with the requirements of the

NGEIR Decision, at that time. Enbridge expects that, if it chooses to conduct TS activities using its unregulated storage capacities, separate from that available from its regulated storage capacities, there will be no requirement to allocate any of the costs or revenues associated with such TS activities.

Second, there has been no allocation of costs related to transportation services for Enbridge's unregulated storage customers. During earlier discussions with stakeholders about Enbridge's storage cost allocation approach, a question arose as to whether the unregulated storage service should be paying additional amounts for such things as transportation services to move gas to Dawn. Earlier in this discussion it was noted that Union and NGTL pay Enbridge for elements of its storage service so as to get the gas that they store in Enbridge's system to and from the Dawn custody point.

The circumstances related to Enbridge's unregulated storage services are different from those that relate to the services provided to Union and NGTL. Those parties have not contributed to the development of the compression and transportation elements of the storage system that are required to move their gas to and from Dawn. They made the investments necessary to make their gas volumes available at a custody point into Enbridge's storage system, but they had not contributed anything to create the system capacities that they required from within the storage system itself.

Conversely, Enbridge's unregulated storage business has made all of the significant investment necessary, in all of the various elements of the storage system (compression, pipelines, metering and other assets), to create and effect the required capacities at Dawn, as well as at other custody points. Without those investments, none of the capacities underlying Enbridge's unregulated storage business would exist. Therefore, if Enbridge's unregulated storage business was to pay to use those assets, it would effectively be paying twice for the facilities and capacities it required. Based upon the cost allocation principles, that would not be appropriate.

ENBRIDGE GAS STORAGE
Capacity and Cost Sharing
Regulated and Unregulated Storage

		2007	2008	2009	2010	2011
Unregulated Storage Capacity as of April 1 (Bcf)		**-**	**3.0**	**5.5**	**7.5**	**12.2**
Regulated Storage Capacity (Bcf)		**98.0**	**98.0**	**98.0**	**98.0**	**98.4**
Total Storage Capacity		**98.0**	**101.0**	**103.5**	**105.5**	**110.6**
	($ millions)					
Direct Unregulated Storage O&M		0.24	0.30	0.78	0.77	0.56
Allocated Storage	- Labour & Overheads	-	0.03	0.10	0.25	0.57
	- Operations & Maintenance	-	0.01	0.11	0.21	0.42
	- Administration & General	-	0.01	0.13	0.23	0.42
Total Unregulated Storage O&M		**0.24**	**0.35**	**1.12**	**1.46**	**1.96**
O&M Allocated to Unregulated		-	0.05	0.34	0.69	1.40
O&M Regulated Storage		8.45	8.22	8.56	9.26	8.76
Total O&M for Storage		**8.45**	**8.27**	**8.90**	**9.95**	**10.16**

Property taxes are included in above numbers

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OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: JUL-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	10.96	88.34%
Un-regulated	12.20	11.07%	1.45	11.66%
	110.2	100.00%	12.41	100.00%

COST CENTRE=25121 (STORAGE ADMINISTRATION)

	Actual	Applicable Share		Annual %	Annual $	Commodity %	Commodity $	Overhead Rate	
CONTROLLABLE COSTS									
60101 BASE PAY	136,066	95%	218,714	100%	218,714	0%	-	69.2%	
60109 TEMPORARY PAYRO	4,842	95%	7,783	100%	7,783	0%	-	69.2%	
60117 VACATION PAY	10,839	95%	17,423	100%	17,423	0%	-	69.2%	
60129 SCHEDULED OVERTIME	(4,730)	95%	(7,603)	100%	(7,603)	0%	-	69.2%	
60131 STATUTORY HOLID	7,961	95%	12,797	100%	12,797	0%	-	69.2%	
60133 SICK PAY	0	95%	-	100%	-	0%	-	69.2%	
60141 VACANCY CREDIT	0	95%	-	100%	-	0%	-	69.2%	
60145 OTHER SALARY EX	0	95%	-	100%	-	0%	-	69.2%	
TOTAL LABOUR	**154,978**		**249,113**		**249,113**		**0**		**27,579**
60401 EMPLOYEE TRAINI	0	95%	-	100%	-	0%	-		
60403 EXECUTIVE DEVELOPMENT	0	100%	-	100%	-	0%	-		
60405 RECRUITMET ADV	0	100%	-	100%	-	0%	-		
60411 AWARDS AND ALLO	2,055	95%	1,952	100%	1,952	0%	-		
61009 SAFETY RELATED	603	100%	603	100%	603	0%	-		
61105 COPIER AND OTHE	4,446	100%	4,446	100%	4,446	0%	-		
61116 COMPUTER SOFTWA	0	100%	-	100%	-	0%	-		
61511 PROFESSIONAL CO	14,945	100%	14,945	100%	14,945	0%	-		
61601 CONTRACT SERVICES	8,925	100%	8,925	100%	8,925	0%	-		
61709 OFFICE REPAIRS	139	100%	139	100%	139	0%	-		
61715 POSTAGE COURIER	282	100%	282	100%	282	0%	-		
61717 REPRODUCTION SE	2,136	100%	2,136	100%	2,136	0%	-		
61910 SITE WORK	1,548	100%	1,548	100%	1,548	0%	-		
61999 OTHER OUTSIDE S	8,792	100%	8,792	100%	8,792	0%	-		
62301 VEHICLE / FLEET	8,000	100%	8,000	90%	7,200	10%	800		
70001 LAND LEASES	554	100%	554	100%	554	0%	-		
70409 OTHER TELECOM S	0	100%	-	100%	-	0%	-		
70501 AIRFARE	25	95%	24	100%	24	0%	-		
70503 GROUND TRANSPOR	956	95%	908	100%	908	0%	-		
70505 ACCOMMODATION	3,893	95%	3,698	100%	3,698	0%	-		
70507 MEALS AND ENTER	2,126	95%	2,020	100%	2,020	0%	-		
70509 OTHER TRAVEL EX	298	95%	283	100%	283	0%	-		
70511 CONFERENCE AND	0	95%	-	100%	-	0%	-		
70701 PROPERTY TAXES	128,706	100%	128,706	100%	128,706	0%	-		
70707 VEHICLE LICENSI	0	100%	-	100%	-	0%	-		
70801 CORPORATE DONAT	1,500	100%	1,500	100%	1,500	0%	-		
70807 SPONSORSHIPS	0	100%	-	100%	-	0%	-		
70809 TRADE AND CIVIC	150	100%	150	100%	150	0%	-		
NON-LABOUR COST CENTRE COSTS	**190,079**		**189,611**		**188,811**		**800**		**20,996**
INTERNAL COST RECOVERIES									
79966 VARIABLE INTERN	(1,000)	100%	(1,000)	100%	(1,000)	0%	-		
79967 OTHER RECOVERIE CAPITAL	(52,008)	100%	(52,008)	100%	(52,008)	0%	-		
TOTAL COST RECOVERIES	**(53,008)**		**(53,008)**		**(53,008)**		**-**		**(5,868)**
TOTAL NET COST CENTRE COSTS	**292,049**		**385,716**		**384,916**		**800**		
				CHARGES TO UN-REGULATED	**42,613**		**93**		
							42,707		

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: JUL-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	10.96	88.34%
Un-regulated	12.20	11.07%	1.45	11.66%
	110.2	100.00%	12.41	100.00%

COST CENTRE=25122 (STORAGE OPERATIONS)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $	Overhead Factor
CONTROLLABLE COSTS							
60101 BASE PAY	10,413	100%	100%	17,189	0%	0	65.1%
60105 HOURLY PAYROLL	68,173	100%	100%	112,536	0%	0	65.1%
60117 VACATION PAY	13,911	100%	100%	22,964	0%	0	65.1%
60129 SCHEDULED OVERT	34,298	100%	80%	45,294	20%	11,323	65.1%
60131 STATUTORY HOLID	4,351	100%	100%	7,182	0%	0	65.1%
60133 SICK PAY	0	100%	100%	0	0%	0	65.1%
60145 OTHER SALARY EX	0	100%	100%	0	0%	0	65.1%
TOTAL LABOUR	**131,146**			**205,165**		**11,323**	
61009 SAFETY RELATED	4,308	100%	100%	4,308	0%	0	
61299 OTHER MATERIALS	7,147	100%	40%	2,859	60%	4,288	
61601 CONTRACT SERVIC	28,010	100%	100%	28,010	0%	0	
61805 ENVIRONMENTAL C	456	100%	100%	456	0%	0	
61999 OTHER OUTSIDE S	59,315	100%	40%	23,726	60%	35,589	
NON-LABOUR COST CENTRE COSTS	**99,236**			**59,359**		**39,877**	
INTERNAL COST RECOVERIES							
79966 VARIABLE INTERN	(937)	100%	100%	(937)	0%	0	100%
79967 OTHER RECOVERIE CAPITAL		100%	100%	0	0%	0	100%
TOTAL COST RECOVERIES	**(937)**			**(937)**		**0**	
TOTAL NET COST CENTRE COSTS	**229,445**			**263,587**		**51,201**	
			CHARGES TO UN-REGULATED	**29,181**		**5,970**	
						35,151	

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: JUL-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	10.96	88.34%
Un-regulated	12.20	11.07%	1.45	11.66%
	110.2	100.00%	12.41	100.00%

COST CENTRE=25123 (STORAGE MAINTENANCE)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $	Overhead Factor
CONTROLLABLE COSTS							
60101 BASE PAY	41,517	100%	100%	70,586	0%	0	70.0%
60105 HOURLY PAYROLL	1,328	100%	100%	2,258	0%	0	70.0%
60117 VACATION PAY	17,995	100%	100%	30,595	0%	0	70.0%
60129 SCHEDULED OVERT	1,538	100%	40%	1,046	60%	1,569	70.0%
60131 STATUTORY HOLID	2,597	100%	100%	4,415	0%	0	70.0%
60133 SICK PAY	923	100%	100%	1,569	0%	0	70.0%
60145 OTHER SALARY EX	0	100%	100%	0	0%	0	70.0%
TOTAL LABOUR	**65,898**			**110,470**		**1,569**	
60401 EMPLOYEE TRAINI	8,259	100%	40%	3,304	60%	4,955	
61299 OTHER MATERIALS	43,415	100%	40%	17,366	60%	26,049	
61601 CONTRACT SERVIC	56,023	100%	40%	22,409	60%	33,614	
NON-LABOUR COST CENTRE COSTS	**107,697**			**43,079**		**64,618**	
INTERNAL COST RECOVERIES							
79951 CAPITAL PROJECT	(3,502)	100%	100%	(3,502)	0%	0	100%
79966 VARIABLE INTERN	(1,600)	100%	100%	(1,600)	0%	0	100%
79967 OTHER RECOVERIE CAPITAL	0	100%	100%	0	0%	0	100%
TOTAL COST RECOVERIES	**(5,102)**			**(5,102)**		**0**	
TOTAL NET COST CENTRE COSTS	**168,493**			**148,446**		**66,187**	
CHARGES TO UN-REGULATED				**16,434**		**7,717**	
						24,152	

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: JUL-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	10.96	88.34%
Un-regulated	12.20	11.07%	1.45	11.66%
	110.2	100.00%	12.41	100.00%

COST CENTRE=25124 (FIELD MAINTENANCE)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $
CONTROLLABLE COSTS						
61299 OTHER MATERIALS	5,741	100%	100%	5,741	0%	0
61511 PROFESSIONAL CO	6,180	100%	100%	6,180	0%	0
61601 CONTRACT SERVIC	34,595	100%	100%	34,595	0%	0
61805 ENVIRONMENTAL C	0	100%	100%	0	0%	0
DIRECT COST CENTRE COSTS	**46,516**			**46,516**		**0**
TOTAL NET COST CENTRE COSTS	**46,516**			**46,516**		**0**
CHARGES TO UN-REGULATED				**5,150**		**0**
						5,150

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REVISED 2011 ADMINISTRATION COST ALLOCATIONS

COST CENTRE=25121 (STORAGE ADMINISTRATION)

	Annual Capacity Bcf	Annual Capacity % of Total	Deliverability Bcf	Deliverability % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.94	82.91%	10.96	88.32%
Un-regulated	12.20	11.07%	0.40	17.09%	1.45	11.68%
	110.20	100%	2.34	100%	12.41	100%

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Commodity	Split of the Balance: Capacity	Split of the Balance: Deliverability	Resulting Allocations: Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
60101 BASE PAY	136,066	100%	69.2%	230,225	5%	75%	25%	71%	164,035	24%	54,678	5%	11,511
60109 TEMPORARY PAYROLL	4,842	100%	69.2%	8,193	5%	75%	25%	71%	5,837	24%	1,946	5%	410
60117 VACATION PAY	10,839	100%	69.2%	18,340	5%	75%	25%	71%	13,067	24%	4,356	5%	917
60129 SCHEDULED OVERTIME	(4,730)	100%	69.2%	(8,003)	5%	75%	25%	71%	(5,702)	24%	(1,901)	5%	(400)
60131 STATUTORY HOLIDAY	7,961	100%	69.2%	13,470	5%	75%	25%	71%	9,597	24%	3,199	5%	674
60133 SICK PAY		100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
60141 VACANCY CREDIT		100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
60145 OTHER SALARY EXPENSES		100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
TOTAL LABOUR	154,978			262,224									
60401 EMPLOYEE TRAINING		100%		-	5%	75%	25%	71%	-	24%	-	5%	-
60403 EXECUTIVE DEVELOPMENT		100%		-	5%	75%	25%	71%	-	24%	-	5%	-
60405 RECRUITMENT ADV		100%		-	5%	75%	25%	71%	-	24%	-	5%	-
60411 AWARDS AND ALLOWANCE	2,055	100%		2,055	5%	75%	25%	71%	1,464	24%	488	5%	103
61009 SAFETY RELATED SUPPLIES	603	100%		603	5%	75%	25%	71%	430	24%	143	5%	30
61105 COPIER & OTHER OFFICE SUPPLIES	4,446	100%		4,446	5%	75%	25%	71%	3,168	24%	1,056	5%	222
61116 COMPUTER SOFTWARE		100%		-	0%	75%	25%	75%	-	25%	-	0%	-
61511 PROFESSIONAL CONSULTING FEES	14,945	100%		14,945	0%	75%	25%	75%	11,209	25%	3,736	0%	-
61601 CONTRACT SERVICES	8,925	100%		8,925	0%	75%	25%	75%	6,694	25%	2,231	0%	-
61707 JANITORIAL SERVICES		100%		-	0%	75%	25%	75%	-	25%	-	0%	-
61709 OFFICE REPAIRS	139	100%		139	0%	75%	25%	75%	104	25%	35	0%	-
61715 POSTAGE COURIER	282	100%		282	0%	75%	25%	75%	212	25%	71	0%	-
61717 REPRODUCTION SERVICES	2,136	100%		2,136	0%	75%	25%	75%	1,602	25%	534	0%	-
61910 SITE WORK	1,548	100%		1,548	0%	75%	25%	75%	1,161	25%	387	0%	-
61999 OTHER OUTSIDE SERVICES	8,792	100%		8,792	5%	75%	25%	71%	6,264	24%	2,088	5%	440
62301 VEHICLE / FLEET	8,000	100%		8,000	10%	75%	25%	68%	5,400	23%	1,800	10%	800
70001 LAND LEASES	554	100%		554	0%	90%	10%	90%	499	10%	55	0%	-
70409 OTHER TELECOM SUPPLIES		100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70501 AIRFARE	25	100%		25	5%	75%	25%	71%	18	24%	6	5%	1
70503 GROUND TRANSPORTATION	956	100%		956	5%	75%	25%	71%	681	24%	227	5%	48
70505 ACCOMMODATION	3,893	100%		3,893	5%	75%	25%	71%	2,774	24%	925	5%	195
70507 MEALS AND ENTERTAINMENT	2,126	100%		2,126	5%	75%	25%	71%	1,515	24%	505	5%	106
70509 OTHER TRAVEL EXPENSES	298	100%		298	5%	75%	25%	71%	212	24%	71	5%	15
70511 CONFERENCE & REGISTRATION FEES		100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70701 PROPERTY TAXES	128,706	100%		128,706	0%	40%	60%	40%	51,482	60%	77,224	0%	-
70707 VEHICLE LICENSING		100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70801 CORPORATE DONATION	1,500	100%		1,500	0%	75%	25%	75%	1,125	25%	375	0%	-
70807 SPONSORSHIPS		100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70809 TRADE & CIVIC MEMBERSHIPS	150	100%		150	0%	75%	25%	75%	113	25%	38	0%	-
TOTAL NON-LABOUR COSTS	190,079			190,079									
79954 GEN & ADMIN RECOVERIES - CAPITAL		100%		0	0%	75%	25%	75%	-	25%	-	0%	-
79956 GEN & ADMIN RECOVERIES - O&M		100%		0	0%	75%	25%	75%	-	25%	-	0%	-
79966 VARIABLE INTERNAL RECOVERIES	(1,000)	100%		(1,000)	0%	75%	25%	75%	(750)	25%	(250)	0%	-
79967 OTHER RECOVERIES - CAPITAL	(52,008)	100%		(52,008)	0%	75%	25%	75%	(39,006)	25%	(13,002)	0%	-
TOTAL INTERNAL COST RECOVERIES	(53,008)			(53,008)									
TOTAL NET COST CENTRE COSTS	292,049			399,295					243,204		141,020		15,071
									60.9%		35.3%		3.8%
									26,925		24,106		1,761
Allocation to Unregulated Storage													52,792

REVISED 2011 OPERATION COST ALLOCATIONS

COST CENTRE=25122 (STORAGE OPERATIONS)

	Annual Capacity Bcf	Annual Capacity % of Total	Deliverability Bcf	Deliverability % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.94	82.91%	10.96	88.32%
Un-regulated	12.20	11.07%	0.40	17.09%	1.45	11.68%
	110.20	100%	2.34	100%	12.41	100%

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Commodity	Split of the Balance Capacity	Split of the Balance Deliverability	Resulting Allocations Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
60101 BASE PAY	10,413	100%	65.1%	17,189	0%	75%	25%	75%	12,892	25%	4,297	0%	0
60105 HOURLY PAYROLL	68,173	100%	65.1%	112,536	0%	75%	25%	75%	84,402	25%	28,134	0%	0
60117 VACATION PAY	13,911	100%	65.1%	22,964	0%	75%	25%	75%	17,223	25%	5,741	0%	0
60129 SCHEDULED OVERTIME	34,298	100%	65.1%	56,617	10%	75%	25%	68%	38,217	23%	12,739	10%	5,662
60131 STATUTORY HOLIDAY PAY	4,351	100%	65.1%	7,182	0%	75%	25%	75%	5,387	25%	1,796	0%	0
60133 SICK PAY		100%	65.1%	-	0%	75%	25%	75%	-	25%	-	0%	0
60145 OTHER SALARY EXPENSES		100%	65.1%	-	0%	75%	25%	75%	-	25%	-	0%	0
TOTAL LABOUR	131,146			216,489									
60401 EMPLOYEE TRAINING & DEVELOPMENT		100%		-	0%	75%	25%	75%	-	25%	-	0%	0
61009 SAFETY RELATED	4,308	100%		4,308	0%	75%	25%	75%	3,231	25%	1,077	0%	0
61299 OTHER MATERIALS & SUPPLIES	7,147	100%		7,147	60%	40%	60%	16%	1,144	24%	1,715	60%	4,288
61601 CONTRACT SERVICES	28,010	100%		28,010	0%	75%	25%	75%	21,008	25%	7,003	0%	0
61805 ENVIRONMENTAL CONTROL	456	100%		456	0%	40%	60%	40%	182	60%	274	0%	0
61999 OTHER OUTSIDE SERVICES	59,315	100%		59,315	60%	40%	60%	16%	9,490	24%	14,236	60%	35,589
TOTAL NON-LABOUR COSTS	99,236			99,236									
79954 GENERAL & ADMIN RECOVERIES - CAPITAL		100%		-	0%	75%	25%	75%	-	25%	-	0%	0
79956 GENERAL & ADMIN RECOVERIES - O&M		100%		-	0%	75%	25%	75%	-	25%	-	0%	0
79966 VARIABLE INTERNAL RECOVERIES	(937)	100%		(937)	0%	75%	25%	75%	(703)	25%	(234)	0%	0
79967 OTHER RECOVERIES - CAPITAL		100%		-	0%	75%	25%	75%	-	25%	-	0%	0
TOTAL INTERNAL COST RECOVERIES	(937)			(937)									
TOTAL NET COST CENTRE COSTS	229,445			314,788					192,472		76,776		45,539
									61.1%		24.4%		14.5%
									21,308		13,124		5,321
Allocation to Unregulated Storage													39,753

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EB-2012-0055
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REVISED 2011 PLANT MAINTENANCE COST ALLOCATIONS

COST CENTRE=25123 (STORAGE MAINTENANCE)

	Annual Capacity Bcf	Annual Capacity % of Total	Deliverability Bcf	Deliverability % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	**88.93%**	1.94	**82.91%**	10.96	**88.32%**
Un-regulated	12.20	**11.07%**	0.40	**17.09%**	1.45	**11.68%**
	110.20	**100%**	2.34	**100%**	12.41	**100%**

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Commodity	Split of the Balance Capacity	Split of the Balance Deliverability	Resulting Allocations Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
60101 BASE PAY	**41,517**	100%	70.0%	70,586	0%	75%	25%	75%	52,940	25%	17,647	0%	-
60105 HOURLY PAYROLL	**1,328**	100%	70.0%	2,258	0%	75%	25%	75%	1,693	25%	564	0%	-
60117 VACATION PAY	**17,995**	100%	70.0%	30,595	0%	75%	25%	75%	22,946	25%	7,649	0%	-
60129 SCHEDULED OVERTIME	**1,538**	100%	70.0%	2,615	60%	75%	25%	30%	784	10%	261	60%	1,569
60131 STATUTORY HOLIDAY	**2,597**	100%	70.0%	4,415	0%	75%	25%	75%	3,312	25%	1,104	0%	-
60133 SICK PAY	**923**	100%	70.0%	1,569	0%	75%	25%	75%	1,177	25%	392	0%	-
60145 OTHER SALARY EXPENSES		100%	70.0%	-	0%	75%	25%	75%	-	25%	-	0%	-
TOTAL LABOUR	**65,898**			**112,039**									
60401 EMPLOYEE TRAINING	**8,259**	100%		8,259	60%	75%	25%	30.0%	2,478	10%	826	60%	4,955
61299 OTHER MATERIALS	**43,415**	100%		43,415	60%	40%	60%	16.0%	6,946	24%	10,420	60%	26,049
70507 MEALS & ENTERTAINMENT		100%		-	5%	75%	25%	71.3%	-	24%	-	5%	-
61601 CONTRACT SERVICES	**56,023**	100%		56,023	60%	40%	60%	16.0%	8,964	24%	13,446	60%	33,614
TOTAL NON-LABOUR COSTS	**107,697**			**107,697**									
79951 CAPITAL PROJECT RECOVERIES	**(3,502)**	100%		(3,502)	0%	75%	25%	75.0%	(2,627)	25%	(876)	0%	-
79966 VARIABLE INTERNAL RECOVERIES	**(1,600)**	100%		(1,600)	0%	75%	25%	75.0%	(1,200)	25%	(400)	0%	-
79967 OTHER RECOVERIES - CAPITAL		100%		-	0%	75%	25%	75.0%	-	25%	-	0%	-
TOTAL INTERNAL COST RECOVERIES	**(5,102)**			**(5,102)**									
TOTAL NET COST CENTRE COSTS	**168,493**			**214,634**					**97,414**		**51,033**		**66,187**
									45.4%		23.8%		30.8%
									10,784		**8,724**		**7,733**
Allocation to Unregulated Storage													**27,241**

5/10/2012

REVISED 2011 FIELD MAINTENANCE COST ALLOCATIONS

COST CENTRE=25124 (FIELD MAINTENANCE)

	Annual Capacity		Deliverability		Commodity	
	Bcf	% of Total	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	**88.93%**	1.94	**82.91%**	10.96	**88.32%**
Un-regulated	12.20	**11.07%**	0.40	**17.09%**	1.45	**11.68%**
	110.20	**100%**	2.34	**100%**	12.41	**100%**

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Commodity	Split of the Balance Capacity	Split of the Balance Deliverability	Resulting Allocations Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
61299 OTHER MATERIALS	**5,741**	100%		5,741	0%	40%	60%	40%	2,296	60%	3,445	0%	-
61511 PROFESSIONAL CONSULTING	**6,180**	100%		6,180	0%	90%	10%	90%	5,562	10%	618	0%	-
61601 CONTRACT SERVICES	**34,595**	100%		34,595	0%	40%	60%	40%	13,838	60%	20,757	0%	-
61805 ENVIRONMENTAL CONTROL		100%		-	0%	40%	60%	40%	-	60%	-	0%	-
TOTAL NON-LABOUR COSTS	**46,516**			46,516									
TOTAL NET COST CENTRE COSTS	**46,516**			**46,516**					**21,696**		**24,820**		**0**
									46.6%		53.4%		0.0%
									2,402		**4,243**		**-**
Allocation to Unregulated Storage													**6,645**

2011 Unregulated Cost Allocation Summary

ORIGINAL METHOD	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Admin	$6,394	$23,453	$41,846	$44,704	$41,278	$62,262	$72,798	$42,707	$52,862	$54,260	$57,640	$107,571	**$ 607,775**
Ops	$15,574	$10,841	$11,369	$25,164	$16,909	$32,057	$23,492	$35,151	$23,608	$40,176	$46,564	$50,204	**$ 331,109**
Plant Maintenance	$30,981	$14,098	$6,420	$21,465	$21,030	$20,072	$6,428	$24,152	$33,442	$23,738	$55,684	$63,499	**$ 321,009**
Field Maintenance	$42,183	($1,993)	$4,062	$21,132	$7,284	($17,655)	$438	$5,150	$36,041	$15,268	$16,108	$13,656	**$ 141,674**
MONTHLY TOTAL	**$95,132**	**$46,399**	**$63,697**	**$112,465**	**$86,501**	**$96,736**	**$103,156**	**$107,160**	**$145,953**	**$133,442**	**$175,996**	**$234,930**	**$ 1,401,567**

NEW METHOD	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Admin	$10,866	$30,355	$56,320	$52,232	$49,142	$73,874	$83,015	$52,792	$63,245	$56,082	$67,178	$129,565	**$ 724,666**
Ops	$20,254	$14,372	$15,328	$27,976	$19,358	$37,027	$26,379	$39,753	$27,547	$43,474	$23,792	$50,581	**$ 345,841**
Plant Maintenance	$39,881	$18,510	$8,547	$23,697	$23,977	$23,416	$6,271	$27,241	$38,853	$23,983	$79,285	$66,884	**$ 380,545**
Field Maintenance	$72,307	($3,435)	$6,961	$23,690	$7,621	($18,010)	$581	$6,645	$47,452	$20,115	$1,865	$18,052	**$ 183,844**
MONTHLY TOTAL	**$143,308**	**$59,802**	**$87,156**	**$127,595**	**$100,098**	**$116,307**	**$116,246**	**$126,431**	**$177,097**	**$143,654**	**$172,120**	**$265,082**	**$ 1,634,896**

UTILITY RATE BASE
COMPARISON OF 2011 HISTORICAL YEAR TO 2010 HISTORICAL YEAR

Line No.		Col. 1 2011 Historical Year	Col. 2 2010 Historical Year	Col. 3 Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	6,064.1	5,807.2	256.9
2.	Accumulated depreciation	(2,398.4)	(2,235.7)	(162.7)
3.	Net property, plant, and equipment	3,665.7	3,571.5	94.2
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	-	0.0
5.	Accounts receivable rebillable projects	1.6	0.5	1.1
6.	Materials and supplies	30.1	24.1	6.0
7.	Mortgages receivable	0.4	0.6	(0.2)
8.	Customer security deposits	(75.6)	(67.1)	(8.5)
9.	Prepaid expenses	1.5	1.3	0.2
10.	Gas in storage	337.6	310.1	27.5
11.	Working cash allowance	(4.3)	(3.3)	(1.0)
12.	Total Working Capital	291.3	266.2	25.1
13.	Utility Rate Base	3,957.0	3,837.7	119.3

Witnesses: K. Culbert
R. Small

UTILITY RATE BASE
COMPARISON OF 2010 HISTORICAL YEAR TO 2009 HISTORICAL YEAR

		Col. 1	Col. 2	Col. 3
Line No.		2010 Historical Year	2009 Historical Year	Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	5,807.2	5,500.5	306.7
2.	Accumulated depreciation	(2,235.7)	(2,089.5)	(146.2)
3.	Net property, plant, and equipment	3,571.5	3,411.0	160.5
	Allowance for Working Capital			
4.	Accounts receivable merchandise finance plan	-	-	-
5.	Accounts receivable rebillable projects	0.5	(0.1)	0.6
6.	Materials and supplies	24.1	26.5	(2.4)
7.	Mortgages receivable	0.6	0.7	(0.1)
8.	Customer security deposits	(67.1)	(53.3)	(13.8)
9.	Prepaid expenses	1.3	1.5	(0.2)
10.	Gas in storage	310.1	406.5	(96.4)
11.	Working cash allowance	(3.3)	1.6	(4.9)
12.	Total Working Capital	266.2	383.4	(117.2)
13.	Utility Rate Base	3,837.7	3,794.4	43.3

Witnesses: K. Culbert
R. Small

UTILITY PROPERTY, PLANT, AND EQUIPMENT
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2011 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	298.1	(109.0)	189.1
2.	Distribution plant	5,387.6	(2,161.9)	3,225.7
3.	General plant	385.7	(126.9)	258.8
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	6,071.9	(2,398.3)	3,673.6
6.	Plant held for future use	1.7	(1.0)	0.7
7.	Sub- total	6,073.6	(2,399.3)	3,674.3
8.	Affiliate Shared Assets Value	(9.5)	0.9	(8.6)
9.	Total property, plant, and equipment	6,064.1	(2,398.4)	3,665.7

Witnesses: K. Culbert
R. Small

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2011	Col. 5 Regulatory Adjustments	Col. 6 Utility Balance Dec.2011	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)	41.7	0.0	-	41.7	(1.0)	40.7	40.6
3.	Structures and improvements (452.00)	14.2	0.3	-	14.5	(0.1)	14.4	14.2
4.	Wells (453.00)	38.5	3.6	-	42.2	-	42.2	39.3
5.	Well equipment (454.00)	8.9	0.0	-	8.9	-	8.9	8.9
6.	Field Lines (455.00)	46.6	13.7	-	60.3	-	60.3	47.3
7.	Compressor equipment (456.00)	90.4	3.3	-	93.6	(0.5)	93.2	91.2
8.	Measuring and regulating equipment (457.00)	11.5	0.0	-	11.5	-	11.5	11.5
9.	Base pressure gas (458.00)	40.9	0.0	-	40.9	-	40.9	40.9
10.	Total	296.8	21.0	-	317.7	(1.5)	316.2	298.1

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2011	Col. 6 Regulatory Adjustments	Col. 7 Utility Balance Dec.2011	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.2)	(0.1)	-	0.1	(2.2)	-	(2.2)	(2.2)
2.	Land and gas storage rights (451.00)	(20.2)	(0.8)	-	-	(21.0)	-	(21.0)	(20.6)
3.	Structures and improvements (452.00)	(4.7)	(0.4)	-	-	(5.1)	0.1	(5.0)	(4.8)
4.	Wells (453.00)	(17.9)	(1.9)	-	1.0	(18.9)	-	(18.9)	(18.8)
5.	Well equipment (454.00)	(4.4)	(0.3)	-	-	(4.7)	-	(4.7)	(4.6)
6.	Field Lines (455.00)	(20.8)	(1.3)	-	-	(22.1)	-	(22.1)	(21.4)
7.	Compressor equipment (456.00)	(30.5)	(2.1)	-	-	(32.6)	0.2	(32.4)	(31.4)
8.	Measuring and regulating equipment (457.00)	(5.0)	(0.4)	-	-	(5.4)	-	(5.4)	(5.2)
9.	Total	(105.7)	(7.3)	-	1.0	(112.0)	0.2	(111.8)	(109.0)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2011	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2011	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	20.4	0.2	-	20.6	-	20.6	20.6
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	7.5	-	-	7.5	-	7.5	7.5
4.	Structures and improvements (472.00)	82.0	4.4	(0.6)	85.8	(0.3)	85.4	82.8
5.	Services, house reg & meter install. (473/474)	2,024.6	103.5	(19.5)	2,108.6	-	2,108.6	2,057.7
6.	NGV station compressors (476)	2.6	0.1	-	2.7	-	2.7	2.6
7.	Meters (478)	367.8	22.6	(7.8)	382.5	-	382.5	371.5
8.	Sub-total	2,504.7	130.8	(27.9)	2,607.6	(0.3)	2,607.3	2,542.6
9.	Mains (475)	2,481.2	141.8	(6.2)	2,616.9	(2.2)	2,614.7	2,526.4
10.	Measuring and regulating equip. (477)	314.9	14.4	(1.0)	328.3	(0.5)	327.7	318.6
11.	Sub-total	2,796.1	156.2	(7.2)	2,945.2	(2.7)	2,942.4	2,845.0
12.	Total	5,300.8	287.1	(35.1)	5,552.8	(3.1)	5,549.7	5,387.6

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2011	Col. 6 Regulatory Adjustment (Note 1)	Col. 7 Utility Balance Dec.2011	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(1.1)	(0.4)	-	-	(1.5)	-	(1.5)	(1.3)
2.	Structures and improvements (472.00)	(5.3)	(2.2)	0.6	0.3	(6.5)	0.1	(6.4)	(6.2)
3.	Services, house reg & meter install. (473/474)	(872.5)	(93.4)	19.5	19.6	(926.8)	-	(926.8)	(902.0)
4.	NGV station compressors (476)	(1.6)	(0.2)	-	-	(1.8)	-	(1.8)	(1.7)
5.	Meters (478)	(92.6)	(9.2)	7.8	(0.5)	(94.5)	-	(94.5)	(94.0)
6.	Mains (475)	(949.2)	(104.9)	6.2	11.3	(1,036.6)	1.4	(1,035.2)	(992.1)
7.	Measuring and regulating equip. (477)	(159.0)	(16.6)	1.0	3.3	(171.3)	0.5	(170.8)	(164.7)
8.	Total	(2,081.2)	(226.8)	35.1	34.0	(2,239.0)	2.0	(2,237.0)	(2,161.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2011	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2011	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	4.8	0.6	-	5.4	(0.2)	5.2	5.0
2.	Office furniture and equipment (483.00)	18.1	5.2	(1.5)	21.8	-	21.8	17.9
3.	Transportation equipment (484.00)	41.0	5.3	(0.2)	46.1	(0.1)	46.0	41.6
4.	NGV conversion kits (484.01)	7.7	0.4	-	8.1	-	8.1	7.8
5.	Heavy work equipment (485.00)	19.3	1.5	(0.3)	20.5	-	20.5	19.4
6.	Tools and work equipment (486.00)	34.3	1.6	(0.0)	35.9	-	35.9	34.4
7.	Rental equipment (487.70)	1.0	0.0	-	1.0	-	1.0	1.0
8.	NGV rental compressors (487.80)	4.9	0.1	(1.2)	3.7	-	3.7	4.8
9.	NGV cylinders (484.02 and 487.90)	2.3	0.1	-	2.4	-	2.4	2.3
10.	Communication structures & equip. (488)	3.0	-	-	3.0	-	3.0	3.0
11.	Computer equipment (490.00)	32.6	8.6	(5.8)	35.3	-	35.3	31.9
12.	Software Aquired/Developed (491.00)	90.2	21.5	(21.8)	90.0	-	90.0	89.5
13.	CIS (491.00)	127.1	-	-	127.1	-	127.1	127.1
14.	Total	386.2	44.8	(30.7)	400.2	(0.3)	400.0	385.7

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2011 ($Millions)	Col. 6 Regulatory Adjustment (Note 1) ($Millions)	Col. 7 Utility Balance Dec.2011 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(3.7)	(0.5)	-	-	(4.2)	0.1	(4.1)	(3.8)
2.	Office furniture and equipment (483.00)	(9.0)	(0.8)	1.5	-	(8.3)	-	(8.3)	(8.6)
3.	Transportation equipment (484.00)	(7.8)	(1.8)	0.2	(0.3)	(9.8)	0.1	(9.7)	(8.7)
4.	NGV conversion kits (484.01)	(4.6)	(0.2)	-	-	(4.8)	-	(4.8)	(4.7)
5.	Heavy work equipment (485.00)	(6.8)	(0.7)	0.3	(0.1)	(7.3)	-	(7.3)	(7.1)
6.	Tools and work equipment (486.00)	(13.1)	(1.0)	0.0	-	(14.1)	-	(14.1)	(13.6)
7.	Rental equipment (487.70)	(1.0)	(0.0)	-	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(3.1)	(0.4)	1.2	-	(2.3)	-	(2.3)	(3.2)
9.	NGV cylinders (484.02 and 487.90)	(1.5)	(0.1)	-	-	(1.6)	-	(1.6)	(1.5)
10.	Communication structures & equip. (488)	(2.1)	(0.1)	-	-	(2.2)	-	(2.2)	(2.2)
11.	Computer equipment (490.00)	(4.4)	(6.3)	5.8	-	(4.9)	-	(4.9)	(2.3)
12.	Software Aquired/Developed (491.00)	(44.0)	(17.9)	21.8	-	(40.1)	-	(40.1)	(48.1)
13.	CIS (491.00)	(15.7)	(12.9)	-	-	(28.6)	-	(28.6)	(22.1)
14.	Total	(116.8)	(42.7)	30.7	(0.4)	(129.2)	0.2	(129.0)	(126.9)

Note 1: Adjustments associated with previously established non-utility items and disallowances.

Witnesses: K. Culbert
R. Small

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2011	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2011	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

Witnesses: K. Culbert
R. Small

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2011	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2011	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

Witnesses: K. Culbert
R. Small

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2011	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2011	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

Witnesses: K. Culbert
R. Small

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2011 HISTORICAL YEAR

Line No.		Col. 1 Opening Balance Dec.2010	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2011	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2011	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(0.9)	(0.1)	-	-	(1.0)	-	(1.0)	(1.0)
2.	Total	(0.9)	(0.1)	-	-	(1.0)	-	(1.0)	(1.0)

Witnesses: K. Culbert
R. Small

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2011 AND ACTUAL 2010

Item No.			Col. 1 Actuals 2011 ($Millions)	Col. 2 Actuals 2010 ($Millions)	Col. 3 2011 Over/(Under) 2010 ($Millions)
A.	Customer Related				
1.1.1	Sales Mains		72.1	46.7	25.4
1.1.2	Services		55.9	52.6	3.3
1.1.3	Meters and Regulation		7.6	8.3	(0.7)
1.1.4	Customer Related Distribution Plant		135.6	107.6	28.0
1.1.5	NGV Rental Equipment		-	0.2	(0.2)
1.1	TOTAL CUSTOMER RELATED CAPITAL		135.6	107.8	27.8
B.	System Improvements and Upgrades				
1.2.1	Mains	- Relocations	15.5	13.2	2.3
1.2.2		- Replacement	54.6	55.7	(1.1)
1.2.3		- Reinforcement	9.8	14.0	(4.2)
1.2.4	Total Improvement Mains		79.8	82.9	(3.1)
1.2.5	Services - Relays		45.9	45.8	0.1
1.2.6	Regulators - Refits		5.6	6.4	(0.8)
1.2.7	Measurement and Regulation		11.4	10.3	1.1
1.2.8	Meters		17.8	13.1	4.7
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES		160.5	158.5	2.0
C.	General and Other Plant				
1.3.1	Land, Structures and Improvements		20.9	14.0	6.9
1.3.2	Office Furniture and Equipment		5.1	1.9	3.2
1.3.3	Transp/Heavy Work/NGV Compressor Equipment		7.4	6.5	0.9
1.3.4	Tools and Work Equipment		1.9	2.5	(0.6)
1.3.5	Computers and Communication Equipment		37.7	32.0	5.7
1.3	TOTAL GENERAL AND OTHER PLANT		73.0	56.9	16.1
D.	Underground Storage Plant		30.1	14.7	15.4
E.	Customer Information System (CIS)		-	(0.3)	0.3
F.	TOTAL CAPITAL EXPENDITURES		399.2	337.6	61.6

Witnesses: L. Au
D. Kelly

ACTUAL 2011 CAPITAL EXPENDITURE WORKSHEET

Item No.		Col. 1 Business as Usual ($Millions)	Col. 2 Safety and Integrity Initiatives ($Millions)	Col. 3 Leave to Construct Projects ($Millions)	Col. 4 Total Actual 2011 ($Millions)
A.	Customer Related				
1.1.1	Sales Mains	52.0		20.1	72.1
1.1.2	Services	55.9			55.9
1.1.3	Meters and Regulation	7.6			7.6
1.1.4	Customer Related Distribution Plant	115.5	-	20.1	135.6
1.1.5	NGV Rental Equipment	-			-
					-
1.1	TOTAL CUSTOMER RELATED CAPITAL	115.5	-	20.1	135.6
B.	System Improvements and Upgrades				
1.2.1	Mains - Relocations	15.5			15.5
1.2.2	- Replacement	46.8	7.8		54.6
1.2.3	- Reinforcement	7.8		2.0	9.8
1.2.4	Total Improvement Mains	70.0	7.8	2.0	79.8
1.2.5	Services - Relays	34.9	11.0		45.9
1.2.6	Regulators - Refits	5.6			5.6
1.2.7	Measurement and Regulation	11.4			11.4
1.2.8	Meters	17.8			17.8
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	139.7	18.8	2.0	160.5
C.	General and Other Plant				-
1.3.1	Land, Structures and Improvements	4.7	16.2		20.9
1.3.2	Office Furniture and Equipment	5.1			5.1
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	7.4			7.4
1.3.4	Tools and Work Equipment	1.9			1.9
1.3.5	Computers and Communication Equipment	37.7			37.7
1.3	TOTAL GENERAL AND OTHER PLANT	56.8	16.2	-	73.0
D.	Underground Storage Plant	30.1			30.1
E.	Customer Information System (CIS)				-
F.	TOTAL CAPITAL EXPENDITURES	342.1	35.0	22.1	399.2

Project Details:				
2.1 Incremental Cast Iron Replacement		18.8		18.8
2.2 Technical Training Facility		16.2		16.2
3.1 York Energy Centre			20.1	20.1
3.2 GTA Reinforcement			1.5	1.5
3.3 Alliston Reinforcement			0.5	0.5
Sub total Additional Initiatives		35.0	22.1	57.1

Witnesses: L. Au
D. Kelly

EXPLANATION OF MAJOR CHANGES
IN ACTUAL 2011 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2010 UTILITY CAPITAL EXPENDITURES

The 2011 Actual was $399.2 million, which is $61.6 million or 18.2% more than the 2010 Actual of $337.6 million. The capital expenditure increase was primarily related to increased requirements for customer related, general plant and storage expenditures. This was partially offset by decreased requirements for system improvements and upgrades. The major categories showing significant variances are explained below:

Item No.

1.1.4 Customer Related Distribution Plant – Increase $28.0 Million

The increase in customer related plant was primarily driven by the "Leave to Construct" York Energy power generation facility ($15.8M) completed in 2011. In addition, increased expenditures were due to higher direct costs related to customer mix ($7.8M). The remaining increase was due to a higher allocation of indirect overheads.

1.2.4 Improvement Mains – Decrease $3.1 Million

The decrease is mainly a reflection of lower allocation of indirect overheads which were prorated between system improvement and customer related direct capital expenditures.

1.2.7 Measurement and Regulation – Increase $1.1 Million

The increase was primarily due to more system regulation requirements relative to 2010. The increase was driven by more aggressive workload and increased material costs in 2011.

Witnesses: L. Au
D. Kelly

1.2.8 Meters – Increase $4.7 Million

The increase reflects the timing of meter purchases relative to 2010. There were more meter purchases in 2011 due to a ramping up of the TC Module upgrade program which was legislated by Measurement Canada to be completed by the end of 2012.

C. General and Other Plant – Increase $16.1 Million

Construction costs related to the Distribution Training and Operations facility accounted for $7.2M of the increase. Computer equipment expenditures increased by $5.7M which was primarily due to software requirements. Furniture requirements increase by $3.2M, primarily due to furniture required for the Distribution Training and Operations facility and other office expansions.

D. Underground Storage Plant – Increase $15.4 million

The increase in storage plant expenditures reflects the on-going efforts of several plant initiatives. The Meter Run Upgrade project was $13.9M. The purpose of this project was to replace and upgrade all storage metering which was largely unchanged since 1964. The increase also included a compliance related project ($2.1M) mandated by the Ministry of Environment for noise emission standards.

Witnesses: L. Au
D. Kelly

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ACTUAL 2010 AND ACTUAL 2009

Item No.		Col. 1 Actuals 2010 ($Millions)	Col. 2 Actuals 2009 ($Millions)	Col. 3 2010 Over/(Under) 2009 ($Millions)
A.	Customer Related			
1.1.1	Sales Mains	46.7	48.2	(1.5)
1.1.2	Services	52.6	48.7	3.9
1.1.3	Meters and Regulation	8.3	11.9	(3.6)
1.1.4	Customer Related Distribution Plant	107.6	108.8	(1.2)
1.1.5	NGV Rental Equipment	0.2	0.2	-
1.1	TOTAL CUSTOMER RELATED CAPITAL	107.8	109.0	(1.2)
B.	System Improvements and Upgrades			
1.2.1	Mains - Relocations	13.2	8.0	5.2
1.2.2	- Replacement	55.7	49.9	5.8
1.2.3	- Reinforcement	14.0	16.8	(2.8)
1.2.4	Total Improvement Mains	82.9	74.7	8.2
1.2.5	Services - Relays	45.8	37.0	8.8
1.2.6	Regulators - Refits	6.4	7.7	(1.3)
1.2.7	Measurement and Regulation	10.3	9.2	1.1
1.2.8	Meters	13.1	15.9	(2.8)
1.2	TOTAL SYSTEM IMPROVEMENTS AND U	158.5	144.5	14.0
C.	General and Other Plant			
1.3.1	Land, Structures and Improvements	14.0	2.9	11.1
1.3.2	Office Furniture and Equipment	1.9	0.9	1.0
1.3.3	Transp/Heavy Work/NGV Compressor Equ	6.5	11.4	(4.9)
1.3.4	Tools and Work Equipment	2.5	2.3	0.2
1.3.5	Computers and Communication Equipmen	32.0	24.8	7.2
1.3	TOTAL GENERAL AND OTHER PLANT	56.9	42.3	14.6
D.	Underground Storage Plant	14.7	4.6	10.1
E.	Customer Information System (CIS)	(0.3)	48.7	(49.0)
F.	TOTAL CAPITAL EXPENDITURES	337.6	349.1	(11.5)

Witnesses: L. Au
D. Kelly

ACTUAL 2010 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 2010 ($Millions)
A.	Customer Related					
1.1.1	Sales Mains	42.1		4.6		46.7
1.1.2	Services	52.6				52.6
1.1.3	Meters and Regulation	8.3				8.3
1.1.4	Customer Related Distribution Plant	103.0	-	4.6	-	107.6
1.1.5	NGV Rental Equipment	0.2				0.2
						-
1.1	TOTAL CUSTOMER RELATED CAPITAL	103.2	-	4.6	-	107.8
B.	System Improvements and Upgrades					
1.2.1	Mains - Relocations	13.2				13.2
1.2.2	- Replacement	49.2	6.5			55.7
1.2.3	- Reinforcement	8.3		5.2	0.5	14.0
1.2.4	Total Improvement Mains	70.7	6.5	5.2	0.5	82.9
1.2.5	Services - Relays	37.8	8.0			45.8
1.2.6	Regulators - Refits	6.4				6.4
1.2.7	Measurement and Regulation	10.3				10.3
1.2.8	Meters	13.1				13.1
1.2	TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	138.3	14.5	5.2	0.5	158.5
C.	General and Other Plant					-
1.3.1	Land, Structures and Improvements	5.0	9.0			14.0
1.3.2	Office Furniture and Equipment	1.9				1.9
1.3.3	Transp/Heavy Work/NGV Compressor Equipment	6.5				6.5
1.3.4	Tools and Work Equipment	2.5				2.5
1.3.5	Computers and Communication Equipment	32.0				32.0
1.3	TOTAL GENERAL AND OTHER PLANT	47.9	9.0	-	-	56.9
D.	Underground Storage Plant	14.7				14.7
E.	Customer Information System (CIS)				(0.3)	(0.3)
F.	TOTAL CAPITAL EXPENDITURES	304.1	23.5	9.8	0.2	337.6
Project Details:						
2.1	Incremental Cast Iron Replacement		12.3			12.3
2.2	Kerotest Valve Replacement		1.6			1.6
2.3	Inside regulators		0.6			0.6
2.4	Technical Training Facility		9.0			9.0
3.1	York Energy Centre			4.6		4.6
3.2	Scarborough Reinforcement			4.7		4.7
3.3	Bathurst Gate Station Reinforcement			0.5		0.5
4.1	Energy Technology				0.5	0.5
4.2	Customer Information System (CIS)				(0.3)	(0.3)
Sub total Additional Initiatives			23.5	9.8	0.2	33.5

Witnesses: L. Au
D. Kelly

EXPLANATION OF MAJOR CHANGES
IN ACTUAL 2010 UTILITY CAPITAL EXPENDITURES
FROM ACTUAL 2009 UTILITY CAPITAL EXPENDITURES

The 2010 Actual was $337.6 million, which is $11.5 million or 3.3% less than the 2009 Actual of $349.1 million. The capital expenditure decrease was primarily related to decreased requirements in Customer Information System ("CIS") and 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 $1.2 Million

The decrease in customer related plant was driven by a lower allocation of indirect costs ($4.7M) and sales mains related to less commercial industrial activity. This was primarily due to the 2009 completion of the Northland Thorold Power generation project which was partially offset by 2010 expenditures for York Energy Centre ($2.6M). The decrease was partially offset by increased expenditures ($6.1M) due to the higher number of customers added in 2010 (36,902) compared to 2009 (32,080).

1.2.4 Improvement Mains – Increase $8.2 Million

The increase reflects higher relocation and replacement activity ($8.5M) in 2010 relative to 2009. This was primarily due to requirements in GTA regions and the Ottawa area as well as increased safety and integrity initiatives related to Kerotest Valve replacement and inside regulator programs ($1.5M). There was also a higher allocation of indirect costs relative to 2009 ($1.0M). These increases were partially offset by a decrease in reinforcement activity ($2.8M)

Witnesses: L. Au
D. Kelly

mainly due to the timing of the Scarborough Reinforcement and Bathurst Gate Reinforcement projects.

1.2.5 Service Relays – Increase $8.8 Million

The increase was primarily due to higher service relay requirements in 2010 ($7.0M) which is reflective of the increased improvement main activity. There was also a higher allocation of indirect costs ($1.8M).

1.2.6 Regulator Refits – Decrease $1.3 Million

The decrease was due to less refit requirements relative to 2009. This activity is mandated by the government inspection meter exchange program, which were lower in 2010.

1.2.7 Measurement and Regulation – Increase $1.1 Million

The increase was primarily due to more system regulation requirements relative to 2009. The increase was driven by a more aggressive workload in 2010 and was also impacted by increased material costs.

1.2.8 Meters – Decrease $2.8 Million

The decrease was primarily due to less meter purchases ($1.0M) and a lower allocation of indirect costs ($1.8M) relative to 2009.

C. General and Other Plant – Increase $14.6 Million

The actual spending in this category increased relative to 2009 actual spending. Land purchased for the Distribution Training and Operations facility accounted for $9.0M of the increase. In addition, structures and improvement requirements increased by $2.1M mainly due to improvements completed at Victoria Park

Centre. Computer equipment expenditures increased by $7.2M which was mainly due to software requirements. Furniture requirements increased by $1.0M. The variance was partially offset by decreased requirements in Transportation and Heavy Work Equipment ($4.9M).

D. Underground Storage Plant – Increase $10.1 million

The increase in storage plant expenditures reflects the completion and on-going efforts of several plant initiatives. The 3D Seismic initiative commenced in 2010 with expenditures of $3.9M. This technology allows for a more comprehensive understanding of the Company's storage pools. The warehouse and maintenance shop was completed in 2010 at a cost of $2.8M. A further increase of $2.1M was due to the Tecumseh/Wilkesport Well completion. The remaining increase was primarily due to a higher allocation of indirect costs ($0.9M) and 2010 land purchase related to compliance with emissions testing ($0.4M).

E. Customer Information System ("CIS") – Decrease $49.0 million

CIS was a multi-year project that commenced in 2007. CIS had a separate approval process with an approved spending of approximately $120M. At the end of 2009 the life to date spend was $127.5 million. The project variance was due to higher system integrator costs and higher interest during construction costs resulting from a delayed implementation and higher interest rates. The $0.3M credit in 2010 reflects an overestimation of 2009 management fees.

Witnesses: L. Au
D. Kelly

UTILITY OPERATING REVENUE
2011 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	1,979.5	(1.1)	1,978.4
2.	Transportation of gas	412.6	(1.4)	411.2
3.	Transmission, compression & storage	1.5	-	1.5
4.	Other operating revenue	40.6	-	40.6
5.	Other income	0.8	-	0.8
6.	Total operating revenue	2,435.0	(2.5)	2,432.5

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2011 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(1.1)	Gas sales Adjustment to gas sales revenue required to reflect normal weather.
2.	(1.4)	Transportation of gas Adjustment to gas transportation revenue required to reflect normal weather.

Witnesses: K. Culbert
R. Small

UTILITY REVENUE
2011 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Revenue ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Revenue ($Millions)
1.	Residential	1,246.8	0.2	1,247.0
2.	Commercial	622.1	-	622.1
3.	Industrial	82.1	-	82.1
4.	Wholesale	28.3	-	28.3
5.	Gas sales	1,979.3	0.2	1,979.5
6.	Transportation of gas	412.6	-	412.6
7.	Transmission, compression & storage	1.5	-	1.5
8.	Service charges & DPAC	13.2	-	13.2
9.	Rent from NGV rentals	0.4	0.1	0.5
10.	Late payment penalties	13.2	-	13.2
11.	Transactional services	12.4	(4.4)	8.0
12.	Open bill revenue	7.0	(1.6)	5.4
13.	Dow Moore recovery	0.3	-	0.3
14.	Affiliate asset use revenue	0.1	(0.1)	-
15.	ABC T-service (net)	5.9	(5.9)	-
16.	Other operating revenue	52.5	(11.9)	40.6
17.	Income from investments	0.5	(0.5)	-
18.	Interest during construction	5.2	(5.2)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	-	-	-
21.	Property/asset use revenue 3rd party	1.2	(1.2)	-
22.	Interest and property rental	6.9	(6.9)	-
23.	Miscellaneous	14.4	(13.7)	0.7
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	0.1	-	0.1
27.	Other income	77.2	(76.4)	0.8
28.	Total revenue	2,530.0	(95.0)	2,435.0

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2011 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	0.2	Residential Gas Sales	
		Remove adjustment related to the updated 2010 tax saving sharing agreement included in the 2011 financials, but already reflected in the 2010 ESM calculation.	
9.	0.1	Rent from NGV rentals	
		NGV revenue imputation to equate the program's overall return to the required regulated return.	
11.	(4.4)	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 2011 TSDA, and shareholder amounts are eliminated from utility returns.	
12.	(1.6)	Open bill revenue	
		To eliminate the shareholder portion of OBSDA and OBAVA write-of	0.2
		To eliminate the shareholder portion of net ex-franchise revenues	(0.2)
		To eliminate the Open Bill shareholder incentive	(1.6)
			(1.6)
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.	(5.9)	ABC T-Service (net)	
		To eliminate the net revenue from ABC T-Service considered to be non-utility. (RP-1999-0001)	

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2011 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(0.5)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(5.2)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
21.	(1.2)	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.	(13.7)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(13.4)
		To eliminate Electric CDM net revenues. Ratepayer amounts were transferred to the 2011 EPESDA and shareholder amounts are eliminated from utility results.	(0.3)
		To eliminate the shareholders' incentive income recorded as a result of calculating the SSMVA amount.	-
			(13.7)
24	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income.	-
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	(62.7)
			(62.7)

Witnesses: K. Culbert
R. Small

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL AND 2011 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2011 Actual	Col. 2 2011 Board Approved Budget	Col. 3 2011 Actual Over (Under) 2011 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	3 601.7	3 356.3	245.4
1.1.2	Rate 1 - T-Service	1 098.2	1 408.1	(309.9)
1.1	Total Rate 1	4 699.9	4 764.4	(64.5)
1.2.1	Rate 6 - Sales	2 323.2	2 235.7	87.5
1.2.2	Rate 6 - T-Service	2 396.8	2 282.7	114.1
1.2	Total Rate 6	4 720.0	4 518.4	201.6
1.3.1	Rate 9 - Sales	0.8	0.4	0.4
1.3.2	Rate 9 - T-Service	0.1	0.2	(0.1)
1.3	Total Rate 9	0.9	0.6	0.3
1.	Total General Service Sales & T-Service	9 420.8	9 283.4	137.4
Contract Sales				
2.1	Rate 100	2.3	0.0	2.3
2.2	Rate 110	66.6	64.5	2.1
2.3	Rate 115	0.1	0.4	(0.3)
2.4	Rate 135	1.4	0.6	0.8
2.5	Rate 145	22.8	22.3	0.5
2.6	Rate 170	48.5	49.9	(1.4)
2.7	Rate 200	168.7	157.4	11.3
2.	Total Contract Sales	310.4	295.1	15.3
Contract T-Service				
3.1	Rate 100	8.0	0.0	8.0
3.2	Rate 110	479.5	407.4	72.1
3.3	Rate 115	558.5	512.7	45.8
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	60.0	49.4	10.6
3.6	Rate 145	161.5	215.0	(53.5)
3.7	Rate 170	474.1	513.3	(39.2)
3.8	Rate 300	30.5	30.0	0.5
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 772.1	1 727.8	44.3
4.	Total Contract Sales & T-Service	2 082.5	2 022.9	59.6
5.	Total	11 503.3	11 306.3	197.0

* There is no distribution volume for Rate 125 customers.

Witnesses: P. Baxter
I. Chan

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2011 ACTUAL AND 2011 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2011 Actual	Col. 2 2011 Board Approved Budget	Col. 3 2011 Actual Over (Under) 2011 Budget (1-2)	Col. 4 2011* Adjustments	Col. 5 2011 Actual Over (Under) 2011 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	3 601.7	3 356.3	245.4	(19.0)	226.4
1.1.2	Rate 1 - T-Service	1 098.2	1 408.1	(309.9)	(6.6)	(316.5)
1.1	Total Rate 1	4 699.9	4 764.4	(64.5)	(25.6)	(90.1)
1.2.1	Rate 6 - Sales	2 323.2	2 235.7	87.5	(36.4)	51.1
1.2.2	Rate 6 - T-Service	2 396.8	2 282.7	114.1	(21.0)	93.1
1.2	Total Rate 6	4 720.0	4 518.4	201.6	(57.4)	144.2
1.3.1	Rate 9 - Sales	0.8	0.4	0.4	0.0	0.4
1.3.2	Rate 9 - T-Service	0.1	0.2	(0.1)	0.0	(0.1)
1.3	Total Rate 9	0.9	0.6	0.3	0.0	0.3
1.	Total General Service Sales & T-Service	9 420.8	9 283.4	137.4	(83.0)	54.4
Contract Sales						
2.1	Rate 100	2.3	0.0	2.3	0.0 **	2.3
2.2	Rate 110	66.6	64.5	2.1	0.0 **	2.1
2.3	Rate 115	0.1	0.4	(0.3)	0.0	(0.3)
2.4	Rate 135	1.4	0.6	0.8	0.0	0.8
2.5	Rate 145	22.8	22.3	0.5	0.0 **	0.5
2.6	Rate 170	48.5	49.9	(1.4)	0.0 **	(1.4)
2.7	Rate 200	168.7	157.4	11.3	1.5	12.8
2.	Total Contract Sales	310.4	295.1	15.3	1.5	16.8
Contract T-Service						
3.1	Rate 100	8.0	0.0	8.0	0.0 **	8.0
3.2	Rate 110	479.5	407.4	72.1	(0.2)	71.9
3.3	Rate 115	558.5	512.7	45.8	0.0 **	45.8
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	60.0	49.4	10.6	0.0	10.6
3.6	Rate 145	161.5	215.0	(53.5)	(0.5)	(54.0)
3.7	Rate 170	474.1	513.3	(39.2)	(1.5)	(40.7)
3.8	Rate 300	30.5	30.0	0.5	0.0	0.5
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 772.1	1 727.8	44.3	(2.2)	42.1
4.	Total Contract Sales & T-Service	2 082.5	2 022.9	59.6	(0.7)	58.9
5.	Total	11 503.3	11 306.3	197.0	(83.7)	113.3

*Note: Weather normalization adjustments have been made to the 2011 Actual utilizing the 2011 Board Approved Budget Degree Days in order to place the two years on a comparable basis.

** Less than 50,000 m

Witnesses: P. Baxter
I. Chan

The principal reasons for the variances contributing to the weather normalized increase of 113.3 10^6m^3 in the 2011 Actual over the 2011 Board Approved Budget are as follows:

1. The volumetric decrease of 90.1 10^6m^3 in Rate 1 was due to a lower average use per customer totalling 88.3 10^6m^3 and an unfavourable customer variance of 1.8 10^6m^3;

2. The volumetric increase of 144.2 10^6m^3 in Rate 6 was due to net customer migration from Contract Sales and T-Service of 66.9 10^6m^3 and a higher average use per customer totaling 231.9 10^6m^3; partially offset by an unfavourable customer variance of 154.6 10^6m^3;

3. The volumetric increase of 0.3 10^6m^3 in Rate 9 was due to a higher average use per station totalling 0.3 10^6m^3;

4. The volumetric increase for Contract Sales and T-Service of 58.9 10^6m^3 was due to increases in the industrial sector of 74.7 10^6m^3, the commercial sector of 29.2 10^6m^3, the apartment sector of 9.1 10^6m^3 and Rate 200 of 12.8 10^6m^3; partially offset by net customer migration to General Service of 66.9 10^6m^3. The increase was primarily attributable to lower gas prices than budgeted and improved business conditions, leading to production line increases and plant expansion.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2011 HISTORICAL YEAR AND 2011 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2011 Actual	Col. 2 2011 Board Approved Budget	Col. 3 2011 Actual Over (Under) 2011 Budget (1-2)	Col. 4 2011* Adjustments	Col. 5 2011 Actual Over (Under) 2011 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 264.0	1 212.3	51.7	(4.9)	46.8
1.1.2	Rate 1 - T-Service	194.9	246.8	(51.9)	(0.6)	(52.5)
1.1	Total Rate 1	1 458.9	1 459.1	(0.2)	(5.5)	(5.7)
1.2.1	Rate 6 - Sales	675.2	663.1	12.1	(8.8)	3.3
1.2.2	Rate 6 - T-Service	178.2	175.9	2.3	(1.3)	1.0
1.2	Total Rate 6	853.4	839.0	14.4	(10.1)	4.3
1.3.1	Rate 9 - Sales	0.2	0.2	0.0 **	0.0	0.0 **
1.3.2	Rate 9 - T-Service	0.0 **	0.0 **	0.0 **	0.0	0.0 **
1.3	Total Rate 9	0.2	0.2	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	2 312.5	2 298.3	14.2	(15.6)	(1.4)
Contract Sales						
2.1	Rate 100	0.6	0.0	0.6	0.0 **	0.6
2.2	Rate 110	14.1	14.6	(0.5)	0.0 **	(0.5)
2.3	Rate 115	0.0 **	0.1	(0.1)	0.0	(0.1)
2.4	Rate 135	0.3	0.1	0.2	0.0	0.2
2.5	Rate 145	4.5	5.0	(0.5)	0.0 **	(0.5)
2.6	Rate 170	9.4	10.0	(0.6)	0.0 **	(0.6)
2.7	Rate 200	28.3	29.4	(1.1)	0.3	(0.8)
2.	Total Contract Sales	57.2	59.2	(2.0)	0.3	(1.7)
Contract T-Service						
3.1	Rate 100	0.5	0.0	0.5	0.0 **	0.5
3.2	Rate 110	13.8	16.0	(2.2)	0.0 **	(2.2)
3.3	Rate 115	7.7	7.9	(0.2)	0.0 **	(0.2)
3.4	Rate 125	7.8	7.3	0.5	0.0 ***	0.5
3.5	Rate 135	2.2	1.8	0.4	0.0	0.4
3.6	Rate 145	5.4	7.8	(2.4)	0.0 **	(2.4)
3.7	Rate 170	5.0	2.9	2.1	0.0 **	2.1
3.8	Rate 300	0.5	0.4	0.1	0.0	0.1
3.9	Rate 315	0.4	0.0	0.4	0.0	0.4
3.	Total Contract T-Service	43.3	44.1	(0.8)	0.0	(0.8)
4.	Total Contract Sales & T-Service	100.5	103.3	(2.8)	0.3	(2.5)
5.	Total	2 413.0	2 401.6	11.4	(15.3)	(3.9)

* Note: Weather normalization adjustments have been made to the 2011 Actuals utilizing the 2011 Board Approved Budget degree days in order to place the two years on a comparable basis. Please refer to Exhibit B, Tab 3, Schedule 2, page 2, for the corresponding volumetric adjustments.

** Less than $50,000

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

Witnesses: P. Baxter
I. Chan

1. Gas sales and transportation of gas revenues for the 2011 Test Year Budget were developed on the basis of EB-2010-0146 rates.

2. The principal reasons for the variances contributing to the increase of $11.4 million in the 2011 Actual over the 2011 Budget are as follows:

3. <u>Gas Sales - Increase of $61.8 Million</u>

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

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

4. <u>Transportation of Gas - Decrease of $50.4 Million</u>

   The decrease in T-service revenue was mainly due to general service customer migration from transportation service to gas sales, partially offset by higher actual transportation charges than budgeted.

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

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2011 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	1 399 998	3 601.7	1 264.0	
1.1.2	Rate 1 - T-Service	402 580	1 098.2	194.9	
1.1	Total Rate 1	1 802 578	4 699.9	1 458.9	
1.2.1	Rate 6 - Sales	121 783	2 323.2	675.2	
1.2.2	Rate 6 - T-Service	35 540	2 396.8	178.2	
1.2	Total Rate 6	157 323	4 720.0	853.4	
1.3.1	Rate 9 - Sales	10	0.8	0.2	
1.3.2	Rate 9 - T-Service	1	0.1	0.0	**
1.3	Total Rate 9	11	0.9	0.2	
1.	Total General Service Sales & T-Service	1 959 912	9 420.8	2 312.5	
Contract Sales					
2.1	Rate 100	5	2.3	0.6	
2.2	Rate 110	34	66.6	14.1	
2.3	Rate 115	1	0.1	0.0	**
2.4	Rate 135	2	1.4	0.3	
2.5	Rate 145	12	22.8	4.5	
2.6	Rate 170	5	48.5	9.4	
2.7	Rate 200	1	168.7	28.3	
2.	Total Contract Sales	60	310.4	57.2	
Contract T-Service					
3.1	Rate 100	10	8.0	0.5	
3.2	Rate 110	171	479.5	13.8	
3.3	Rate 115	27	558.5	7.7	
3.4	Rate 125	4	0.0 *	7.8	
3.5	Rate 135	40	60.0	2.2	
3.6	Rate 145	114	161.5	5.4	
3.7	Rate 170	32	474.1	5.0	
3.8	Rate 300	8	30.5	0.5	
3.9	Rate 315	0	0.0	0.4	
3.	Total Contract T-Service	406	1 772.1	43.3	
4.	Total Contract Sales & T-Service	466	2 082.5	100.5	
5.	Total	1 960 378	11 503.3	2 413.0	

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

Witnesses: P. Baxter
I. Chan

ENBRIDGE GAS DISTRIBUTION
DETAILS OF OTHER REVENUE AND OTHER INCOME
2011 HISTORICAL AND 2010 HISTORICAL

Item No.		Col. 1 2011 Historical ($Millions)	Col. 2 2010 Historical ($Millions)	Col. 3 2011 Historical Over/(Under) 2010 Historical ($Millions)
1.1	Service Charges & DPAC	13.2	13.0	0.2
1.2	Rental Revenue - NGV Program	0.5	0.8	(0.3)
1.3	Late Payment Penalties	13.2	13.1	0.1
1.4	Dow Moore Recovery	0.3	0.2	0.1
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Ontario Power Authority Program Revenue *	-	11.7	(11.7)
1.7	Miscellaneous	0.8	1.6	(0.8)
1.8	Open Bill Revenue	5.4	5.4	-
1.9	Total Other Revenue	41.4	53.8	(12.4)

Note: The 2011 Ontario Power Authority Program Revenue reflects the ratepayer share of the net revenue ssociated within the Electric Program Earnings Sharing Deferral Account rather than in the ESMDA as a result of the 2010 Earnings Sharing Agreement.

Witness: R. Lei

ENBRIDGE GAS DISTRIBUTION
DETAILS OF OTHER REVENUE AND OTHER INCOME
2010 HISTORICAL and 2009 HISTORICAL

		Col. 1	Col. 2	Col. 3
Item No.		2010 Historical ($Millions)	2009 Historical ($Millions)	2010 Historical Over/(Under) 2009 Historical ($Millions)
1.1	Service Charges & DPAC	13.0	12.7	0.3
1.2	Rental Revenue - NGV Program	0.8	0.6	0.2
1.3	Late Payment Penalties	13.1	14.0	(0.9)
1.4	Dow Moore Recovery	0.2	0.2	-
1.5	Transactional Services (net)	8.0	8.0	-
1.6	Ontario Power Authority Program Revenue	11.7	5.9	5.8
1.7	Miscellaneous	1.6	1.6	-
1.8	Open Bill Revenue	5.4	5.4	-
1.9	Total Other Revenue	53.8	48.4	5.4

Witness: R. Lei

COST OF SERVICE
2011 HISTORICAL YEAR

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,384.8	(1.1)	1,383.7
2.	Operation and maintenance	360.5	-	360.5
3.	Depreciation and amortization expense	276.6	-	276.6
4.	Fixed financing costs	2.8	-	2.8
5.	Debt redemption premium amortization	0.3	-	0.3
6.	Company share of IR agreement tax savings	22.3	-	22.3
7.	Municipal and other taxes	37.6	-	37.6
8.	Operating costs	2,084.9	(1.1)	2,083.8
9.	Income tax expense			57.0
10.	Cost of service			2,140.8

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2011 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	(1.1)	Gas Costs
		Adjustment required to gas costs to reflect normal weathe

Witnesses: K. Culbert
R. Small

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2011 HISTORICAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	348.7	348.7	
	Add			
2.	Depreciation and amortization	276.6	276.6	
3.	Other	-	-	
4.	Other non-deductible items	1.0	1.0	
5	Total Add Back	277.6	277.6	
6.	Sub-total	626.3	626.3	
	Deduct			
7.	Capital cost allowance	232.9	232.9	
8.	Items capitalized for regulatory purposes	46.3	46.3	
9.	Deduction for "grossed up" Part VI.1 tax	2.9	2.9	
10.	Amortization of share/debenture issue expense	4.0	4.0	
11.	Amortization of cumulative eligible capital	0.4	0.4	
12	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Profit on sale of assets	-	-	
14.	Total Deduction	286.6	286.6	
15	Taxable income	339.7	339.7	
16.	Income tax rates	16.50%	11.75%	
17.	Provision	56.1	39.9	96.0
18.	Part VI.1 tax			1.0
19.	Investment tax credit			-
20.	Total taxes excluding interest shield			97.0
	Tax shield on interest expense			
21.	Rate base	3,957.0		
22.	Return component of debt	3.58%		
23.	Interest expense	141.5		
24.	Combined tax rate	28.250%		
25	Income tax credit			(40.0)
26	Total utility income taxes			57.0

Witnesses: K. Culbert
R. Small

COST OF SERVICE
2011 HISTORICAL YEAR

Line No.		Col. 1 EGDI Ont. Corporate Costs and Expenses ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Costs and Expenses ($Millions)
1.	Gas costs	1,384.8	-	1,384.8
2.	Operation and maintenance	394.3	(33.8)	360.5
3.	Depreciation	244.6	(0.5)	244.1
4.	Amortization	32.5	-	32.5
5.	Depreciation and amortization	277.1	(0.5)	276.6
6.	Fixed financing costs	2.8	-	2.8
7.	Debt redemption premium amortization	0.3	-	0.3
8.	Company share of IR agreement tax savings	-	22.3	22.3
9.	Municipal and other taxes	37.8	(0.2)	37.6
10.	Capital taxes	1.0	(1.0)	-
11.	Municipal and other taxes	38.8	(1.2)	37.6
12.	Interest on long-term debt	136.1	(136.1)	-
13.	Amortization of preference share issue costs and debt discount and expense	3.9	(3.9)	-
14.	Interest and financing amortization	140.0	(140.0)	-
15.	Interest on short-term debt	7.5	(7.5)	-
16.	Interest due affiliates	26.8	(26.8)	-
17.	Other interest expense	34.3	(34.3)	-
18.	Total operating costs	2,272.4	(187.5)	2,084.9
19.	Current taxes	49.9	(49.9)	-
20.	Deferred taxes	(0.2)	0.2	-
21.	Income tax expense	49.7	(49.7)	-
22.	Cost of service	2,322.1	(237.2)	2,084.9

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2011 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
2.	(33.8)	Operation and maintenance expense	
		Interest paid on security deposits held during the year and included in the elimination of interest expense. The expense is incurred to reduce bad debts. The average amount of the security deposits held during the year is applied as a reduction to the allowance for working capital in rate base.	1.0
		To eliminate donations (EBRO 490).	(3.0)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.8)
		To eliminate Corporate Cost allocations above RCAM amount.	(16.7)
		To eliminate non-utility green energy costs.	(0.1)
		To eliminate ESM amounts contained in the Corporate financials.	(13.0)
		Incremental allocation to unregulated storage - B&V study	(0.2)
			(33.8)
3.	(0.5)	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).	(0.3)
			(0.5)
8.	22.3	Company share of IR agreement tax savings	
		To reflect the impact of the shareholder portion of agreed tax savings on utility income.	
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	
10.	(1.0)	Capital taxes	
		Adjustment to capital taxes needed to convert the capital tax calculation to a utility "stand-alone" basis.	

Witnesses: K. Culbert
R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2011 HISTORICAL YEAR

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
12.	(136.1)	Interest on long-term debt Expense of capital.
13.	(3.9)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
15.	(7.5)	Interest on short-term debt Expense of capital.
16.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
19.	(49.9)	Income taxes - current Income tax expense related to corporate earnings.
20.	0.2	Income taxes - deferred Income tax expense related to corporate earnings.

Witnesses: K. Culbert
R. Small

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2011 HISTORICAL YEAR

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2011	UCC Carry Forward
1	2,020,987,302	0	0	0	4.00%	(80,839,492)	1,940,147,810
51	825,925,327	229,589,706	0	114,794,853	6.00%	(56,443,211)	999,071,822
2	138,025,159	0	(159,751)	(79,876)	6.00%	(8,276,717)	129,588,691
6	16,851	0	0	0	10.00%	(1,685)	15,166
8	8,880,021	5,029,342	0	2,514,671	20.00%	(2,278,938)	11,630,425
10	23,260,699	5,955,130	(130,889)	2,912,121	30.00%	(7,851,846)	21,233,094
12	13,641,256	29,898,337	(20,000)	14,939,169	100.00%	(28,580,425)	14,939,169
12	60,086,330	0	0	0	50.00%	(30,043,165)	30,043,165
17	38,261	0	0	0	8.00%	(3,061)	35,200
38	5,484,786	2,728,011	(46,014)	1,340,999	30.00%	(2,047,735)	6,119,048
41	30,715,175	16,203,000	0	8,101,500	25.00%	(9,704,169)	37,214,006
13	1,306,431	4,660,000	0	2,330,000		(249,000)	5,717,431
3	262,293	0	0	0	5.00%	(13,115)	249,178
45	1,618,999	0	0	0	45.00%	(728,550)	890,449
50	3,882,533	15,033,000	0	7,516,500	55.00%	(6,269,468)	12,646,065
52	0	0	0	0	100.00%	-	0
Total	3,134,131,423	309,096,526	(356,654)	154,369,936		(233,330,576)	3,209,540,719

Non-utility and shared asset eliminations	385,683
Utility Federal CCA	(232,944,893)

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 F2011	UCC Carry Forward
1	2,020,987,302	0	0	0	4.00%	(80,839,492)	1,940,147,810
51	825,925,327	229,589,706	0	114,794,853	6.00%	(56,443,211)	999,071,822
2	138,025,159	0	(159,751)	(79,876)	6.00%	(8,276,717)	129,588,691
6	16,851	0	0	0	10.00%	(1,685)	15,166
8	8,880,021	5,029,342	0	2,514,671	20.00%	(2,278,938)	11,630,425
10	23,260,699	5,955,130	(130,889)	2,912,121	30.00%	(7,851,846)	21,233,094
12	13,641,256	29,898,337	(20,000)	14,939,169	100.00%	(28,580,425)	14,939,169
12	60,086,330	0	0	0	50.00%	(30,043,165)	30,043,165
17	38,261	0	0	0	8.00%	(3,061)	35,200
38	5,484,786	2,728,011	(46,014)	1,340,999	30.00%	(2,047,735)	6,119,048
41	30,715,175	16,203,000	0	8,101,500	25.00%	(9,704,169)	37,214,006
13	1,306,431	4,660,000	0	2,330,000		(249,000)	5,717,431
3	262,293	0	0	0	5.00%	(13,115)	249,178
45	1,618,999	0	0	0	45.00%	(728,550)	890,449
50	3,882,533	15,033,000	0	7,516,500	55.00%	(6,269,468)	12,646,065
52	0	0	0	0	100.00%	-	-
Total	3,134,131,423	309,096,526	(356,654)	154,369,936		(233,330,576)	3,209,540,719

Non-utility and shared asset eliminations	385,683
Utility Provincial CCA and UCC	(232,944,893)

Witnesses: K. Culbert
R. Small

ENBRIDGE GAS DISTRIBUTION
OPERATING AND MAITENANCE EXPENSE BY DEPARTMENT
CALENDAR YEAR ENDING DECEMBER 31, 2011

Line No.	Particulars ($ 000's)	Col. 1 Actual 2011	Col. 2 Actual 2010	Col. 3 Actual 2009	Col. 4 Actual 2008	Col. 5 2011 Actual Over/(Under) 2010 Actual	Col. 6 OEB Approved 2007 Utility O&M
1.	Finance	$ 6,196	$ 6,016	$ 5,981	$ 5,843	$ 180	$ 8,380
2.	Risk Management	2,459	2,141	2,865	1,695	318	1,986
3.	Customer Care Service Charges	64,190	68,742	82,042	84,583	(4,552)	83,493
4.	Customer Care Internal Costs	7,360	9,222	7,868	9,679	(1,862)	7,302
5.	Provision for Uncollectibles	21,542	11,500	17,855	16,660	10,042	15,105
6.	Energy Supply, Storage, Regulatory	11,757	12,587	11,827	12,368	(830)	14,900
7.	Legal and Corporate Security	4,146	1,407	1,170	1,147	2,739	1,207
8.	Operations	59,195	60,580	55,170	53,540	(1,385)	54,893
9.	Information Technology	30,893	30,398	22,695	21,247	495	21,790
10.	Business Development & Customer Strategy (excluding DSM)	15,631	18,567	14,255	13,364	(2,936)	19,118
11.	Human Resources (excluding benefits)	20,031	15,127	14,568	13,272	4,904	13,059
12.	Benefits	27,488	27,335	26,241	24,597	153	21,405
13.	Pipeline Integrity and Safety	29,695	25,318	21,167	19,722	4,377	17,820
14.	Public and Government Affairs	7,381	6,582	5,331	4,723	798	4,759
15.	Non Departmental Expenses	31,130	25,822	31,332	30,258	5,308	18,307
16.	Corporate Cost Allocations (including direct costs)	43,440	36,692	34,266	32,166	6,748	18,100
17.	Total	382,534	358,036	354,633	344,866	24,498	321,624
18.	Capitalization (A&G)	(24,482)	(24,330)	(23,902)	(21,643)	(152)	(17,424)
19.	Total Net Utility Operating and Maintenance Expense, Excluding DSM	358,052	333,706	330,731	323,223	24,346	304,200
20.	Demand Side Management Programs (DSM)	26,708	25,468	24,255	23,100	1,240	22,000
21.	Total Net Utility Operating and Maintenance Expense	$384,760	$359,174	$354,986	$346,323	$ 25,586	$ 326,200
22.	Regulatory Adjustments						
23.	To eliminate Corporate Cost Allocations above RCAM	(16,725)	(12,428)	(13,100)	(13,066)	(4,296)	
24.	To eliminate CIS fees above Customer Care settlement agreement	-	-	(4,900)	(9,811)	-	
25.	To eliminate Conservation Services	(7,292)	-	-	-	(7,292)	
26.	Incremental O&M Allocated to Unregulated Storage	(233)	-	-	-	(233)	
27.	Total Adjustments	(24,249)	(12,428)	(18,000)	(22,877)	(11,821)	
28.	Utility O&M	$360,511	$346,746	$336,986	$323,446	$ 13,764	

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations, and other utility adjustments.
2) Historical years including the 2007 OEB approved budget have been restated based on the 2011 organization structure.

Witnesses: R. Lei
A. Patel

EXPLANATION OF MAJOR CHANGES
ACTUAL 2011 O&M EXPENSES COMPARED TO ACTUAL 2010 O&M EXPENSES

The 2011 Actual Utility O&M was $360.5 million, which was $13.8 million higher than the 2010 Actual Utility O&M of $346.7 million. The increase was primarily driven by higher provision for uncollectibles, compensation costs, damage prevention, environmental, health and safety costs. The increased O&M costs were partially offset by lower customer care costs, operational outside service costs, and conservation services spending.

Line No:

3. Customer Care Service Charges: decreased by $4.6 million primarily due to lower bill and payment production costs and lower contract pricing.

4. Customer Care Internal Costs: decreased by $1.9 million as a result of lower consulting charges and licensing fees.

5. Provision for Uncollectibles: increased by $10.0 million mainly due to adjustments required to correct deficiencies in accounts receivable reporting that were recognized in 2011.

7. Legal and Corporate Security: increased by $2.7 million resulting from the centralization of legal expenses in the Legal department.

8. Operations: decreased by $1.4 million primarily due to lower outside services, well logging work, and higher damage recovery.

10. Business Development & Customer Strategy: decreased by $2.9 million mainly due to lower conservation services spending. For the purposes of ESM, conservation services

are eliminated for utility O&M starting in 2011 since there is a separate sharing mechanism as per the Settlement Agreement on EB-2011-0008.

11. Human Resources: increased by $4.9 million primarily attributed to higher employee services and benefits, severances, and higher rents and leases.

13. Pipeline Integrity and Safety: increased by $4.4 million mainly due to higher damage prevention costs and Environment, Health, and Safety costs.

15. Non Departmental Expenses: increased by $5.3 million largely due to higher compensation related costs.

16. Corporate Cost Allocations: increased by $6.7 million primarily driven by higher compensation related costs and insurance premium.

20. Demand Side Management: increased by $1.2 million due to the higher level of Board Approved program spending.

Witnesses: R. Lei
A. Patel

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
'2011 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
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,319.6	58.62	6.02	3.529	139.7
2.	Short-Term Debt	112.9	2.85	1.61	0.046	1.8
3.		2,432.5	61.47		3.575	
4.	Preference Shares	100.0	2.53	2.40	0.061	2.4
						143.9
5.	Common Equity	1,424.5	36.00	8.94	3.218	
6.		3,957.0	100.00		6.854	
7.	Rate Base (Ex. B-2-1)	($Millions)			3,957.0	
8.	Utility Income (Ex. B-5-2)	($Millions)			291.70	
9.	Indicated Rate of Return				7.372	
10.	Sufficiency in Rate of Return				0.518	
11.	Net Sufficiency	($Millions)			20.50	
12.	Gross Sufficiency	($Millions)			28.57	
13.	Revenue at Existing Rates	($Millions)			2,391.02	
14.	Revenue Requirement	($Millions)			2,362.45	
15.	Gross Revenue Sufficiency	($Millions)			28.57	
	Common Equity					
16.	Allowed Rate of Return				8.940	
17.	Earnings on Common Equity				10.38	
18.	Sufficiency in Common Equity Return				1.44	

Witnesses: K. Culbert
R. Small

UTILITY INCOME
2011 HISTORICAL YEAR

Line No.		Col. 1 Utility Income ($Millions)
1.	Gas sales	1,978.4
2.	Transportation of gas	411.2
3.	Transmission, compression and storage revenue	1.5
4.	Other operating revenue	40.6
5.	Interest and property rental	-
6.	Other income	0.8
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,432.5
8.	Gas costs	1,383.7
9.	Operation and maintenance	360.5
10.	Depreciation and amortization expense	276.6
11.	Fixed financing costs	2.8
12.	Debt redemption premium amortization	0.3
13.	Company share of IR agreement tax savings	22.3
14.	Municipal and other taxes	37.6
15.	Interest and financing amortization expense	-
16.	Other interest expense	-
17.	Cost of service (Ex. B-4-1-pg.1)	2,083.8
18.	Utility income before income taxes	348.7
19.	Income tax expense (Ex. B-4-1-pg.3)	57.0
20.	Utility income	291.7

Witnesses: K. Culbert
R. Small

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2011 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	2,353.0		141.6
2.	Unamortized Finance Costs	(33.4)		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,319.6		141.6
5.	Calculated Cost Rate		6.02%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.61%	
	Preference Shares			
7.	Preference Share Summary	100.0		2.4
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		2.4
11.	Calculated Cost Rate		2.40%	
	Common Equity			
12.	Board Approved Formula ROE		7.94%	
13.	100 Basis Point Allowance Before Earnings Sharing		1.00%	
14.	Total Allowed ROE for ESM Purposes		8.94%	

Witnesses: K. Culbert
R. Small

DEFERRAL & VARIANCE ACCOUNTS
REQUESTED FOR CLEARANCE OCTOBER 1, 2012

1. The deferral and variance accounts EGD is requesting clearance of at October 1, 2012 are shown at page 2 of this schedule. The balances requested for clearance total approximately $(9.6) 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 explanatory 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. The interest calculated on the principal balances has been updated to include the use of the Board's April 1, 2012 prescribed interest rate for deferral and variance accounts. The eventual interest amounts to be cleared will be calculated using any updated Board prescribed quarterly interest rate that becomes effective before the approved date of clearance.

Witnesses: K. Culbert
R. Small

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at March 31, 2012 Principal ($000's)	Col. 2 Actual at March 31, 2012 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2012 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2012 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2010 DSMVA	(2,717.1)	(93.6)	(2,717.1)	(113.4) [1]
2.	Lost Revenue Adjustment Mechanism	2010 LRAM	-	-	(42.9)	(0.5) [1]
3.	Shared Savings Mechanism V/A	2010 SSMVA	-	-	4,155.3	25.5 [1]
4.	Class Action Suit D/A	2012 CASDA	4,709.5	449.4	4,709.5	484.2 [2]
5.	Deferred Rebate Account	2011 DRA	(308.7)	(1.9)	(308.7)	(4.3)
6.	Gas Distribution Access Rule Costs D/A	2011 GDARCDA	226.6	1.7	2,758.1	- [3]
7.	Ontario Hearing Costs V/A	2011 OHCVA	(1,031.9)	(4.1)	(1,031.9)	(11.9) [4]
8.	Unbundled Rate Implementation Cost D/A	2011 URICDA	139.7	1.5	139.7	2.7
9.	Municipal Permit Fees D/A	2011 MPFDA	1,082.0	-	429.4	- [3]
10.	Average Use True-Up V/A	2011 AUTUVA	(2,948.9)	(10.8)	(2,948.9)	(32.4) [5]
11.	Tax Rate and Rule Change V/A	2011 TRRCVA	(1,200.0)	(9.1)	(1,200.0)	(18.1)
12.	Earnings Sharing Mechanism D/A	2011 ESMDA	(14,100.0)	(51.8)	(14,300.0)	(155.6) [6]
13.	Mean Daily Volume Mechanism D/A	2012 MDVMDA	152.1	0.2	616.1	- [7]
14.	Mean Daily Volume Mechanism D/A	2011 MDVMDA	2,537.3	29.2	-	- [7]
15.	Mean Daily Volume Mechanism D/A	2010 MDVMDA	1,280.4	23.5	-	- [7]
16.	Mean Daily Volume Mechanism D/A	2009 MDVMDA	42.4	0.8	-	- [7]
17.	Electric Program Earnings Sharing D/A	2011 EPESDA	(247.5)	(0.9)	(247.5)	(2.7)
18.	Ex-Franchise Third Party Billing Services D/A	2011 EFTPBSDA	(234.4)	(0.9)	(234.4)	(2.7)
19.	Open Bill Service Deferral Account	2012 OBSDA	153.5	1.3	87.7	1.2 [8]
20.	Open Bill Access Variance Account	2012 OBAVA	139.0	1.3	79.4	1.1 [8]
21.	Total non commodity related accounts		(12,326.0)	335.8	(10,056.2)	173.1
	Commodity Related Accounts					
22.	Transactional Services D/A	2011 TSDA	(7,357.0)	(49.2)	(7,357.0)	(103.2)
23.	Unaccounted for Gas V/A	2011 UAFVA	8,536.2	24.5	8,536.2	87.5
24.	Storage and Transportation D/A	2011 S&TDA	(910.0)	(8.7)	(910.0)	(15.3)
25.	Total commodity related accounts		269.2	(33.4)	269.2	(31.0)
26.	Total Deferral and Variance Accounts		(12,056.8)	302.4	(9,787.0)	142.1

Notes:
1. The final 2010 DSMVA, LRAM, and SSMVA balances to be cleared will be those approved in EB-2012-0192.
2. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years (2008 - 2012). The 2008 installment was cleared in July and August 2008, the 2009 installment was cleared in April and May 2010, the 2010 installment was cleared in January 2011, and the 2011 installment was cleared in October 2011. The Company is requesting clearance of the 2012, or fifth and final installment in this proceeding.
3. The forecast 2011 GDARCDA and 2011 MPFDA clearance amounts are the result of revenue requirement calculations found in evidence at Ex.C-1-2 and C-1-3.
4. The OHCVA calculation is found in evidence at Ex.C-1-6.
5. The AUTUVA explanation is found in evidence at Ex.C-1-4.
6. The ESMDA explanation is found in evidence at Ex.B-1-1 and B-1-2.
7. The forecast 2012 MDVMDA clearance amount is the result of a revenue requirement calculation, found in evidence at Ex. C-1-5, based on the consolidated balance of the 2009 through 2012 MDVMDA's.
8. The forecast OBSDA and OBAVA balances are in accordance with the EB-2009-0043 approved Settlement Agreement.

Witnesses: K. Culbert
R. Small

GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNT

1. In the EB-2010-0146 Rate Order, the Board approved a 2011 Gas Distribution Access Rule Costs Deferral Account ("GDARCDA") to record costs associated with the Company maintaining compliance with the Board's Gas Distribution Access Rule directives.

2. EGD recorded all costs incurred in 2011, both capital and operating, in the 2011 deferral account. This includes capital of $0.1M related to Customer Service Rule ("CSR") changes which come into effect in 2012. Clearance of these CSR related costs is not being requested at this time, because the full impact of CSR changes is not currently known.

3. In the EB-2007-0615 Final Rate Order, EB-2009-0055 Decision, EB-2010-0042 Decision, and the EB-2011-0008 Decision the Board approved clearance of the 2007, 2008, 2009, and 2010 GDAR compliance costs through revenue requirement calculations, which were included as part of one time rate rider adjustments to customers. The result is that the Company's distribution rates do not contain the ongoing impact of GDAR compliance spending, and therefore, associated rate rider adjustments need to be established and cleared annually. As a result, the cumulative 2012 revenue requirement impact of the 2007, 2008, 2009, 2010, and 2011 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 a partial 2012 annual revenue requirement (excluding CSR related costs) determined through a revenue requirement / cost of service type of calculation, for the 2007 through 2011 cumulative expenditures. This revenue requirement treatment is consistent with

the EB-2007-0615, EB-2009-0055, EB-2010-0042, and EB-2011-0008 Board Decisions.

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 in the partial revenue requirement calculation, as it is the underlying capital structure in base rates and used in EGD's 2008-2012 Incentive Regulation approved rates mechanism. This is consistent with the 2007, 2008, 2009, and 2010 Approved GDARCDA revenue requirement determinations.

5. The Company is proposing to recover $2.8 million as part of the requested one time rate rider adjustment in October 2012, as shown in the proposed clearance balances at Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4. The determination of the partial 2012 annual revenue requirement associated with the combined 2007, 2008, 2009, 2010, and 2011 GDAR deferral account costs is shown in pages 3 through 7 of this schedule.

6. As previously indicated, 2011 spending on CSR changes have not been included in the determination of this GDAR revenue requirement. EGD will not know the full cost or impact of the required CSR changes to the 2012 revenue requirement, until the end of 2012. Incremental costs of implementing the new CSR's, in addition to those incurred in 2011, will be recorded in the Board approved GDARCDA (EB-2011-0277). In 2013, the Company will request clearance of an incremental 2012 revenue requirement, utilizing amounts captured in the 2012 GDARCDA and the residual amount in the 2011 GDARCDA.

ONTARIO UTILITY CAPITAL STRUCTURE
2007, 2008, 2009, 2010 & 2011 GDARCDA IMPACTS

2007 Approved Capital Structure

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

	($ 000's)	2008	2009	2010	2011	2012
7.	Ontario Utility Income	(73.7)	(78.5)	(1,491.0)	(1,655.1)	(1,683.9)
8.	Rate base	6,273.7	5,455.9	4,251.9	2,640.3	1,028.7
9.	Indicated rate of return	(1.17)%	(1.44)%	(35.07)%	(62.69)%	(163.69)%
10.	(Def.) / suff. in rate of return	(8.75)%	(9.02)%	(42.65)%	(70.27)%	(171.27)%
11.	Net (def.) / suff.	(548.9)	(492.1)	(1,813.4)	(1,855.3)	(1,761.9)
12.	Gross (def.) / suff.	(859.3)	(770.4)	(2,838.8)	(2,904.4)	(2,758.1)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY RATE BASE
2007, 2008, 2009, 2010 & 2011 GDARCDA IMPACTS

($ 000's)

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

ONTARIO UTILITY INCOME
2007, 2008, 2009, 2010 & 2011 GDARCDA IMPACTS

Line No.	($ 000's)	2008	2009	2010	2011	2012
	Revenue					
1.	Gas sales	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-
5.	Other income	-	-	-	-	-
6.	Total revenue	-	-	-	-	-
	Costs and expenses					
7.	Gas costs	-	-	-	-	-
8.	Operation and Maintenance	40.4	124.8	130.2	134.3	139.1
9.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
10.	Municipal and other taxes	10.4	1.1	-	-	-
11.	Total costs and expenses	1,512.4	1,667.1	1,741.8	1,745.9	1,750.7
12.	Utility income before inc. taxes	(1,512.4)	(1,667.1)	(1,741.8)	(1,745.9)	(1,750.7)
	Income taxes					
13.	Excluding interest shield	(1,338.3)	(1,501.3)	(182.7)	(48.5)	(50.3)
14.	Tax shield on interest expense	(100.4)	(87.3)	(68.1)	(42.3)	(16.5)
15.	Total income taxes	(1,438.7)	(1,588.6)	(250.8)	(90.8)	(66.8)
16.	Ontario utility net income	(73.7)	(78.5)	(1,491.0)	(1,655.1)	(1,683.9)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2007, 2008, 2009, 2010 & 2011 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
1.	Utility income before income taxes	(1,512.4)	(1,667.1)	(1,741.8)	(1,745.9)	(1,750.7)
	Add Backs					
2.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
7.	Sub total - pre-tax income plus add backs	(50.8)	(125.9)	(130.2)	(134.3)	(139.1)
	Deductions					
8.	Capital cost allowance - Federal	3,654.5	4,030.3	375.7	-	-
9.	Capital cost allowance - Provincial	3,654.5	4,030.3	375.7	-	-
10.	Items capitalized for regulatory purposes	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-
16.	Total Deductions - Federal	3,654.5	4,030.3	375.7	-	-
17.	Total Deductions - Provincial	3,654.5	4,030.3	375.7	-	-
18.	Taxable income - Federal	(3,705.3)	(4,156.2)	(505.9)	(134.3)	(139.1)
19.	Taxable income - Provincial	(3,705.3)	(4,156.2)	(505.9)	(134.3)	(139.1)
20.	Income tax provision - Federal	(819.6)	(919.4)	(111.9)	(29.7)	(30.8)
21.	Income tax provision - Provincial	(518.7)	(581.9)	(70.8)	(18.8)	(19.5)
22.	Income tax provision - combined	(1,338.3)	(1,501.3)	(182.7)	(48.5)	(50.3)
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(1,338.3)	(1,501.3)	(182.7)	(48.5)	(50.3)
	Tax shield on interest expense					
26.	Rate base as adjusted	6,273.7	5,455.9	4,251.9	2,640.3	1,028.7
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	277.9	241.7	188.4	117.0	45.6
29.	Combined tax rate	36.120%	36.120%	36.120%	36.120%	36.120%
30.	Income tax credit	(100.4)	(87.3)	(68.1)	(42.3)	(16.5)
31.	Total income taxes	(1,438.7)	(1,588.6)	(250.8)	(90.8)	(66.8)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY REVENUE REQUIREMENT
2007, 2008, 2009, 2010 & 2011 GDARCDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Cost of capital					
1.	Rate base	6,273.7	5,455.9	4,251.9	2,640.3	1,028.7
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	475.5	413.6	322.3	200.1	78.0
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	40.4	124.8	130.2	134.3	139.1
6.	Depreciation and amortization	1,461.6	1,541.2	1,611.6	1,611.6	1,611.6
7.	Municipal and other taxes	10.4	1.1	-	-	-
8.	Cost of service	1,512.4	1,667.1	1,741.8	1,745.9	1,750.7
	Misc. & Non-Op. Rev					
9.	Other operating revenue	-	-	-	-	-
10.	Other income	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-
	Income taxes on earnings					
12.	Excluding tax shield	(1,338.3)	(1,501.3)	(182.7)	(48.5)	(50.3)
13.	Tax shield provided by interest expense	(100.4)	(87.3)	(68.1)	(42.3)	(16.5)
14.	Income taxes on earnings	(1,438.7)	(1,588.6)	(250.8)	(90.8)	(66.8)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	(859.3)	(770.4)	(2,838.8)	(2,904.4)	(2,758.1)
16.	Net (def.) / suff.	(548.9)	(492.1)	(1,813.4)	(1,855.3)	(1,761.9)
17.	Taxes on (def.) / suff.	310.4	278.3	1,025.4	1,049.1	996.2
18.	Revenue requirement	859.6	770.4	2,838.7	2,904.3	2,758.1
	Revenue at existing Rates					
19.	Gas sales	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.3	0.0	(0.1)	(0.1)	0.0
23.	Revenue at existing rates	0.3	0.0	(0.1)	(0.1)	0.0
24.	Gross revenue (def.) / suff.	(859.3)	(770.4)	(2,838.8)	(2,904.4)	(2,758.1)

Witnesses: K. Culbert
R. Small

MUNICIPAL PERMIT FEES DEFERRAL ACCOUNT

1. In the EB-2010-0146 Rate Order, the Board approved the 2011 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 2011 deferral account are capital expenditure related (as were amounts related to the Boards approval of previous 2008 through 2010 accounts).

3. In the EB-2009-0055, EB-2010-0042, and EB-2011-0008 Decisions, the Board approved clearance of the 2008, 2009, and 2010 MPFDA costs through a revenue requirement calculation, to be cleared to customers as a one time rate rider adjustment. As a result, the Company's distribution rates do not contain the ongoing impact of the 2008, 2009, and 2010 MPFDA spending. Therefore associated rate rider adjustments need to be established and cleared annually. As a result, the cumulative 2012 revenue requirement impact of the 2008, 2009, 2010, and 2011 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 2012 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation, for the 2008, 2009, 2010, and 2011 cumulative expenditures. This revenue requirement treatment is consistent with past Board Decisions regarding the clearance of the 2008, 2009, and 2010 MPFDA's, and multiple decisions regarding the clearance of GDARCDA amounts. The

treatment/clearance of MPFDA costs in the same manner as GDARCDA costs is appropriate as the costs for each are predominantly capital expenditure related.

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

5. The Company is proposing to recover $0.4 million as a one time billing adjustment in October 2012, as shown in the proposed one time clearance balances at Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4. The determination of the 2012 annual revenue requirement associated with the 2008, 2009, 2010, and 2011 MPFDA is shown in pages 3 through 7 of this schedule.

ONTARIO UTILITY CAPITAL STRUCTURE
2008, 2009, 2010 & 2011 MPFDA IMPACTS

2007 Approved Capital Structure

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

	($ 000's)	2008	2009	2010	2011	2012
7.	Ontario Utility Income	(1.6)	(12.9)	(25.6)	(47.7)	(69.6)
8.	Rate base	204.3	1,038.8	1,838.0	2,717.8	3,261.8
9.	Indicated rate of return	(0.78)%	(1.24)%	(1.39)%	(1.76)%	(2.13)%
10.	(Def.) / suff. in rate of return	(8.36)%	(8.82)%	(8.97)%	(9.34)%	(9.71)%
11.	Net (def.) / suff.	(17.1)	(91.6)	(164.9)	(253.8)	(316.7)
12.	Gross (def.) / suff. (Note: 1)	(25.7)	(136.7)	(239.0)	(353.7)	(429.4)

Note: 1 Includes 2008 permit fees of $0.7 million, 2009 permit fees of $0.9 million, 2010 permit fees of $0.9 million, and 2011 permit fees of $1.1 million. Permit fees in 2012 and beyond will increase the prospective annual revenue requirements.

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY RATE BASE
2008, 2009, 2010 & 2011 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Property, plant, and equipment					
1.	Cost or redetermined value	207.0	1,070.6	1,937.1	2,924.6	3,617.3
2.	Accumulated depreciation	(2.7)	(31.8)	(99.1)	(206.8)	(355.5)
3.		204.3	1,038.8	1,838.0	2,717.8	3,261.8
	Allowance for working capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-
12.		-	-	-	-	-
13.	Ontario utility rate base	204.3	1,038.8	1,838.0	2,717.8	3,261.8

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY INCOME
2008, 2009, 2010 & 2011 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Revenue					
1.	Gas sales	-	-	-	-	-
2.	Transportation of gas	-	-	-	-	-
3.	Transmission and compression	-	-	-	-	-
4.	Other operating revenue	-	-	-	-	-
5.	Other income	-	-	-	-	-
6.	Total revenue	-	-	-	-	-
	Costs and expenses					
7.	Gas costs	-	-	-	-	-
8.	Operation and Maintenance	-	-	-	-	-
9.	Depreciation and amortization	10.7	48.6	86.7	130.3	158.4
10.	Municipal and other taxes	1.6	3.5	1.7	-	-
11.	Total costs and expenses	12.3	52.1	88.4	130.3	158.4
12.	Utility income before inc. taxes	(12.3)	(52.1)	(88.4)	(130.3)	(158.4)
	Income taxes					
13.	Excluding interest shield	(7.7)	(24.0)	(37.6)	(48.6)	(50.9)
14.	Tax shield on interest expense	(3.0)	(15.2)	(25.2)	(34.0)	(37.9)
15.	Total income taxes	(10.7)	(39.2)	(62.8)	(82.6)	(88.8)
16.	Ontario utility net income	(1.6)	(12.9)	(25.6)	(47.7)	(69.6)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2008, 2009, 2010 & 2011 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
1.	Utility income before income taxes	(12.3)	(52.1)	(88.4)	(130.3)	(158.4)
	Add Backs					
2.	Depreciation and amortization	10.7	48.6	86.7	130.3	158.4
3.	Large corporation tax	-	-	-	-	-
4.	Other non-deductible items	-	-	-	-	-
5.	Any other add back(s)	-	-	-	-	-
6.	Total added back	10.7	48.6	86.7	130.3	158.4
7.	Sub total - pre-tax income plus add backs	(1.6)	(3.5)	(1.7)	-	-
	Deductions					
8.	Capital cost allowance - Federal	21.5	69.3	119.6	172.0	194.1
9.	Capital cost allowance - Provincial	21.5	69.3	119.6	172.0	194.1
10.	Items capitalized for regulatory purposes	-	-	-	-	-
11.	Deduction for "grossed up" Part V1.1 tax	-	-	-	-	-
12.	Amortization of share and debt issue expense	-	-	-	-	-
13.	Amortization of cumulative eligible capital	-	-	-	-	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-	-	-	-	-
15.	Any other deduction(s)	-	-	-	-	-
16.	Total Deductions - Federal	21.5	69.3	119.6	172.0	194.1
17.	Total Deductions - Provincial	21.5	69.3	119.6	172.0	194.1
18.	Taxable income - Federal	(23.1)	(72.8)	(121.3)	(172.0)	(194.1)
19.	Taxable income - Provincial	(23.1)	(72.8)	(121.3)	(172.0)	(194.1)
20.	Income tax provision - Federal	(4.5)	(13.8)	(21.8)	(28.4)	(29.1)
21.	Income tax provision - Provincial	(3.2)	(10.2)	(15.8)	(20.2)	(21.8)
22.	Income tax provision - combined	(7.7)	(24.0)	(37.6)	(48.6)	(50.9)
23.	Part V1.1 tax	-	-	-	-	-
24.	Investment tax credit	-	-	-	-	-
25.	Total taxes excluding tax shield on interest expense	(7.7)	(24.0)	(37.6)	(48.6)	(50.9)
	Tax shield on interest expense					
26.	Rate base as adjusted	204.3	1,038.8	1,838.0	2,717.8	3,261.8
27.	Return component of debt	4.43%	4.43%	4.43%	4.43%	4.43%
28.	Interest expense	9.1	46.0	81.4	120.4	144.5
29.	Combined tax rate	33.500%	33.000%	31.000%	28.250%	26.250%
30.	Income tax credit	(3.0)	(15.2)	(25.2)	(34.0)	(37.9)
31.	Total income taxes	(10.7)	(39.2)	(62.8)	(82.6)	(88.8)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY REVENUE REQUIREMENT
2008, 2009, 2010 & 2011 MPFDA IMPACTS

($ 000's)

Line No.		2008	2009	2010	2011	2012
	Cost of capital					
1.	Rate base	204.3	1,038.8	1,838.0	2,717.8	3,261.8
2.	Required rate of return	7.58%	7.58%	7.58%	7.58%	7.58%
3.	Cost of capital	15.5	78.7	139.3	206.0	247.2
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-
6.	Depreciation and amortization	10.7	48.6	86.7	130.3	158.4
7.	Municipal and other taxes	1.6	3.5	1.7	-	-
8.	Cost of service	12.3	52.1	88.4	130.3	158.4
	Misc. & Non-Op. Rev					
9.	Other operating revenue	-	-	-	-	-
10.	Other income	-	-	-	-	-
11.	Misc, & Non-operating Rev.	-	-	-	-	-
	Income taxes on earnings					
12.	Excluding tax shield	(7.7)	(24.0)	(37.6)	(48.6)	(50.9)
13.	Tax shield provided by interest expense	(3.0)	(15.2)	(25.2)	(34.0)	(37.9)
14.	Income taxes on earnings	(10.7)	(39.2)	(62.8)	(82.6)	(88.8)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	(25.7)	(136.7)	(239.0)	(353.7)	(429.4)
16.	Net (def.) / suff.	(17.1)	(91.6)	(164.9)	(253.8)	(316.7)
17.	Taxes on (def.) / suff.	8.6	45.1	74.1	99.9	112.7
18.	Revenue requirement	25.7	136.7	239.0	353.6	429.5
	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	(0.1)	0.1
23.	Revenue at existing rates	0.0	0.0	0.0	(0.1)	0.1
24.	Gross revenue (def.) / suff.	(25.7)	(136.7)	(239.0)	(353.7)	(429.4)

Witnesses: K. Culbert
R. Small

2011 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2011 Average Use True-up Variance Account ("AUTUVA") amount.

2. Table 1 of Appendix A details the calculations that result in the amount of $2.95 million that will be credited to rate payers. The refund was primarily attributable to favourable Rate 6 average use variances, partially offset by a shortfall in residential average usages.

3. Factors contributing to favourable Rate 6 average use variances are as follows:

   (a) Ongoing rate switching between contract and general service rate classes, discussed in the next paragraph; and

   (b) Lower actual natural gas prices than expected and a gradual recovery from the economic conditions experienced during 2008-2009 led to an increase in consumption for multiple large volume customers that migrated from contract rates during 2006 to 2011. These large volume customers' gas usages are much more energy intensive, price sensitive and heterogeneous than the typical general service Rate 6 customers as defined for this rate class.[1] Examples for these large volume customers are large combined-cycle, natural gas-fired electrical power plants, several large automobile manufacturers, a large corn ethanol production facility, various large food & beverage, chemical and other manufacturing plants.

[1] Large volume customers are usually referred to having annual consumption exceeding 340,000 cubic metres. General service customers are usually attributed to having annual consumption lower than 340,000 cubic metres.

4. Tables 2 and 3 in the Appendix illustrate that a majority of the net rate switching gains from contract rates to Rate 6 were impacted by the following:

   (a) Changes to rate design as stated at EB-2010-0146, Exhibit B, Tab 1, Schedule 5, pages 6 to 8;
   (b) Unexpected production cuts or plant consolidation for certain customers that either had specific business reasons or had not recovered from the economic conditions experienced during 2008-2009 in contrast to other customer experiences mentioned on page 1; and
   (c) A number of Rate 145 interruptible customers migrated to Rate 6 in 2011 unexpectedly. This is due to the removal of the Rate 145 72-hour curtailment notice rate offering along with the associated curtailment credit in order to increase the effectiveness and reliability of curtailment. In turn, this will enhance the effectiveness and reliability of the Company's gas supply planning. This removal was approved through the Board's acceptance of the Settlement Agreement for the System Reliability Decision as filed at EB-2010-2031, Exhibit C, Tab 1, Schedule 1, Appendix B, in late July 2010 after the 2011 Contract Market Volume Budget was already completed in early July 2010.

5. As highlighted in the 2011 volume budget evidence filed at EB-2010-0146, Exhibit B, Tab 1, Schedule 5, pages 5 and 6, Rate 1 average use budget numbers had not incorporated the impact of conservation activities undertaken by customers due to the implementation of the Harmonized Sales Tax ("HST") as suggested by Ontario Finance Minister.[2] In fact, 2011 actual data was the first year to reflect the full-year impact of the HST since its implementation in July 2010.

[2] Ontario matching energy incentives. Toronto Star, 31, Mar. 2009. http://www.thestar.com/printArticle/610800.

6. Prior to July 2010, natural gas bills were exempt from the provincial sales tax (8%). However, with the implementation of the blended tax rate effective July 2010, home energy costs increased by 8% all else being equal. As a result, customers reacted to this as a further increase in gas charges. This might have further encouraged customers to reduce natural gas usage by taking advantage of energy retrofit or other energy programs promoted by both Federal and Provincial governments.

7. Other than the HST impact, the ongoing difficulties encountered in explicitly identifying and applying the estimated energy savings resulting from various energy efficiency and conservation initiatives or trends always pose a downward risk to the residential average use budget: [3]

- an increase in the minimum performance level, Annual Fuel Utilization Efficiency ("AFUE"), for residential gas-fired furnaces will be 90% (high-efficiency) instead of the previously 78% (medium-efficiency) effective December 31, 2009; and
- other green energy technologies, various conservation initiatives originated by customers themselves or promoted by government programs (e.g., Ontario Green Energy Act, ecoENERGY Retrofit, Ontario Home Energy Audit and Retrofit, Ontario Solar Thermal Heating Incentive, ecoENERGY Efficiency program).

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

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[3] As indicated at EB-2010-0146, Exhibit B, Tab 1, Schedule 5, Page 13, only less than 50,000 m^3 was budgeted for other conservation resulting from these initiatives.

9. As filed in response to VECC's Interrogatory #8, at EB-2008-0219, Exhibit I, Tab 7, Schedule 8, part(d), the numerical calculation of Table 1 was previously illustrated and explained. In accordance with the settlement agreement filed at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 15 and 16 and EB-2007-0615, Decision and Rate Order, Appendix C, page 25, the purpose of the AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6, and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use 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.

10. As was the case in previous rate case proceedings, the audited actual volume savings of DSM activities will not be available until later in the 2012 year. Therefore, 2011 Board Approved Budget DSM volumes still represent an accurate estimate of 2011 actual.

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

Witnesses: P. Baxter
I. Chan

TABLE 1

2011 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Exhibit Reference:	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	Unit Rate of the Revenue Impact, exclusive of gas costs	=Col. 9*10
Rate Class	2011 Budget Annual Use (m^3)	2011 Normalized Actual Annual Use (m^3)	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2011 DSM Budget (10^6m^3)	2011 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 - Refund to Rate Payers ($ millions)
1	2,643	2,594	(49)	1,804,189	(88.3)	(12.7)	(12.7)	0.0	(88.3)	0.0551	(4.86)
6	28,029	29,471	1,442	160,827	231.9	(26.1)	(26.1)	0.0	231.9	0.0337	7.81
Total					143.6	(38.8)	(38.8)	0.0	143.6		2.95

Witnesses: P. Baxter
I. Chan

TABLE 2
CUSTOMER MIGRATION FROM CONTRACT RATE CLASS TO RATE 6
BETWEEN 2011 ACTUAL AND 2010 ACTUAL

Table 2 - Customer Migration from Contract Rate to Rate 6
Between 2011 Actual and 2011 Board Approved Budget

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

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	12	Apartment	2.1
	1	Education Services	0.3
	1	Primary Metal & Machinery	1.4
Total	14		3.8

2. Customers migrated to rate 6 due to production cuts or plants consolidation

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	4	All Other Industrial	1.6
	2	Asphalt	0.1
	3	Chemical and Chemical Products	0.9
	1	Education Services	0.5
	3	Electronics/High Tech	7.2
	5	Food, Beverage, Drug & Tobacco	12.2
	1	Health, Social & Other Services	0.2
	1	Hotels	0.5
	1	Non-Metallic Mineral Products	0.0
	4	Primary Metal & Machinery	7.8
	3	Pulp & Paper	4.9
	1	Transportation Equipment	1.3
	3	Wholesale & Retail Trade	2.2
Total	32		39.4

3. Customers migrated to rate 6 due to the removal of Rate 145 72 hour curtailment notice

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	52	Apartment	26.1
	1	Business & Financial Service Industries	0.0
	1	Chemical and Chemical Products	0.1
	2	Food, Beverage, Drug & Tobacco	0.9
	1	Government Services	0.2
	7	Greenhouses/Agriculture	1.8
	3	Health, Social & Other Services	0.9
	1	Refined Petroleum	1.1
	1	Transportation and Storage and Utilities	0.4
Total	69		31.5
Grand Total	**115**		**74.7**

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

Witnesses: P. Baxter
I. Chan

TABLE 3
CUSTOMER MIGRATION FROM RATE 6 TO CONTRACT RATE CLASS
BETWEEN 2011 ACTUAL AND 2010 ACTUAL

Table 3 - Customer Migration from Rate 6 to Contract
Between 2011 Actual and 2011 Board Approved Budget

1. Customers already migrated to Rate 6 in 2011 (Timing)

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	(2)	All Other Industrial	(1.3)
	(1)	Chemical and Chemical Products	(3.7)
	(1)	Food, Beverage, Drug & Tobacco	(0.5)
	(1)	Primary Metal & Machinery	(0.2)
	(2)	Pulp & Paper	(2.1)
Total	(7)		(7.8)

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

Witnesses: P. Baxter
I. Chan

TABLE 4
GENERAL SERVICE RATE 1
2011 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 ($10^6 m^3$)	793.6	803.2	670.1	492.9	332.9	164.7	105.4	107.0	108.9	167.5	349.6	578.5	4,674.3	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	1,792,234	1,795,395	1,799,789	1,799,377	1,801,411	1,799,375	1,796,089	1,798,310	1,803,083	1,808,433	1,815,424	1,822,016	1,802,578	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.1
1.3	Average Use per Customer (m^3)	443	447	372	274	185	92	59	59	60	93	193	318	2,594	

Witnesses: P. Baxter
I. Chan

TABLE 5
GENERAL SERVICE RATE 6
2011 ACTUAL - NORMALIZED VOLUME, CUSTOMERS, AVERAGE USE

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Exhibit Reference
Item.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	Normalized Volumes (10^6m^3)	694.8	795.7	761.2	490.9	340.2	175.5	110.7	103.0	116.1	172.8	344.1	557.6	4,662.6	Exhibit B, Tab 3, Schedule 2
1.2	Customer Meters	157,878	158,622	159,909	158,979	158,482	156,838	155,785	155,178	155,138	155,337	157,019	158,709	157,323	Exhibit B, Tab 3, Schedule 4, Col. 1 Item 1.2
1.3	Average Use per Customer (m^3)	4,401	5,017	4,760	3,088	2,147	1,119	711	664	748	1,113	2,191	3,513	29,471	

Witnesses: P. Baxter
I. Chan

MEAN DAILY VOLUME MECHANISM DEFERRAL ACCOUNT

1. In the Board's Decision and Order in the Commodity, Load Balancing and Cost Allocation proceeding (EB-2008-0106), EGD was required to develop and adopt a Mean Daily Volume Mechanism which EGD has done for use commencing in 2012. The Board approved an associated Mean Daily Volume Mechanism Deferral Account ("MDVMDA") for each of 2009, 2010, 2011, and within the EB-2011-0277 Partial Decision and Rate Order, a 2012 MDVMDA. Incremental costs required to accommodate the mechanism were incurred in 2009 through 2012 and the amount being requested for clearance through the 2012 MDVMDA is the 2012 revenue requirement related to those costs.

2. The Company is not seeking to recover the total amount of cash expended, as is the case for many deferral accounts, but is proposing to recover on a one time basis the 2012 annual revenue requirement, determined through a revenue requirement / cost of service type of calculation. This revenue requirement treatment is consistent with past Board Decisions regarding the clearance of deferral accounts which contain any costs that are capital expenditure related.

3. The revenue requirement calculation, shown in pages 3 through 7 of this exhibit, 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, as it is the underlying capital structure within base rates which are used in EGD's 2008-2012 Incentive Regulation approved rates mechanism.

Witnesses: K. Culbert
R. Small

4. The Company is proposing to recover $0.6 million as a one time billing adjustment in October 2012, as shown within the proposed one time clearance balances at Exhibit C, Tab 1, Schedule 1, page 2, Columns 3 and 4.

ONTARIO UTILITY CAPITAL STRUCTURE
2009, 2010, 2011 & 2012 MDVMDA 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)	2012
7.	Ontario Utility Income	(183.1)
8.	Rate base	3,580.4
9.	Indicated rate of return	(5.11)%
10.	(Def.) / suff. in rate of return	(12.69)%
11.	Net (def.) / suff.	(454.4)
12.	Gross (def.) / suff.	(616.1)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY RATE BASE
2009, 2010, 2011 & 2012 MDVMDA IMPACTS

($000's)

Line No.		2012
	Property, plant, and equipment	
1.	Cost or redetermined value	3,924.7
2.	Accumulated depreciation	(344.3)
3.		3,580.4
	Allowance for working capital	
4.	Accounts receivable merchandise finance plan	-
5.	Accounts receivable rebillable projects	-
6.	Materials and supplies	-
7.	Mortgages receivable	-
8.	Customer security deposits	-
9.	Prepaid expenses	-
10.	Gas in storage	-
11.	Working cash allowance	-
12.		-
13.	Ontario utility rate base	3,580.4

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY INCOME
2009, 2010, 2011 & 2012 MDVMDA IMPACTS

($000's)

Line No.		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	751.3
10.	Municipal and other taxes	-
11.	Total costs and expenses	751.3
12.	Utility income before inc. taxes	(751.3)
	Income taxes	
13.	Excluding interest shield	(526.6)
14.	Tax shield on interest expense	(41.6)
15.	Total income taxes	(568.2)
16.	Ontario utility net income	(183.1)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2009, 2010, 2011 & 2012 MDVMDA IMPACTS

($000's)

Line No.		2012
1.	Utility income before income taxes	(751.3)
	Add Backs	
2.	Depreciation and amortization	751.3
3.	Large corporation tax	-
4.	Other non-deductible items	-
5.	Any other add back(s)	-
6.	Total added back	751.3
7.	Sub total - pre-tax income plus add backs	-
	Deductions	
8.	Capital cost allowance - Federal	2,006.1
9.	Capital cost allowance - Provincial	2,006.1
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	2,006.1
17.	Total Deductions - Provincial	2,006.1
18.	Taxable income - Federal	(2,006.1)
19.	Taxable income - Provincial	(2,006.1)
20.	Income tax provision - Federal	(300.9)
21.	Income tax provision - Provincial	(225.7)
22.	Income tax provision - combined	(526.6)
23.	Part V1.1 tax	-
24.	Investment tax credit	-
25.	Total taxes excluding tax shield on interest expense	(526.6)
	Tax shield on interest expense	0.1
26.	Rate base as adjusted	3,580.4
27.	Return component of debt	4.43%
28.	Interest expense	158.6
29.	Combined tax rate	26.250%
30.	Income tax credit	(41.6)
31.	Total income taxes	(568.2)

Witnesses: K. Culbert
R. Small

ONTARIO UTILITY REVENUE REQUIREMENT
2009, 2010, 2011 & 2012 MDVMDA IMPACTS

($000's)

Line No.		2012
	Cost of capital	
1.	Rate base	3,580.4
2.	Required rate of return	7.58%
3.	Cost of capital	271.4
	Cost of service	
4.	Gas costs	-
5.	Operation and Maintenance	-
6.	Depreciation and amortization	751.3
7.	Municipal and other taxes	-
8.	Cost of service	751.3
	Misc. & Non-Op. Rev	
9.	Other operating revenue	-
10.	Other income	-
11.	Misc, & Non-operating Rev.	-
	Income taxes on earnings	
12.	Excluding tax shield	(526.6)
13.	Tax shield provided by interest expense	(41.6)
14.	Income taxes on earnings	(568.2)
	Taxes on (def) / suff.	
15.	Gross (def.) / suff.	(616.1)
16.	Net (def.) / suff.	(454.4)
17.	Taxes on (def.) / suff.	161.7
18.	Revenue requirement	616.2
	Revenue at existing Rates	
19.	Gas sales	0.0
20.	Transportation service	0.0
21.	Transmission, compression and storage	0.0
22.	Rounding adjustment	0.1
23.	Revenue at existing rates	0.1
24.	Gross revenue (def.) / suff.	(616.1)

Witnesses: K. Culbert
R. Small

2011
ENBRIDGE GAS DISTRIBUTION
ONTARIO HEARING COSTS
VARIANCE ACCOUNT

Line No.	Test Year Proceeding Costs	Col. 1 Baseline Regulatory Cost Budget ($000's)	Col. 2 2011 Regulatory Costs Incurred ($000's)	Col. 3 Variance ($000's)
1.	Legal	840.0	238.1	
2.	Intervenor	1,155.0	259.7	
3.	Ontario Energy Board	4,040.0	3,098.1	
4.	Consultants	500.0	16.7	
5.	Transcripts, newspaper notices, printing, other	420.0	277.8	
6.	Sub-total	6,955.0	3,890.4	
7.	Other proceedings	1,887.5	920.2	
8.	2009 Agreed to OHCVA threshold reduction	(3,000.0)	-	
9.	Actual versus OHCVA threshold variance	5,842.5	4,810.6	(1,031.9)

Line No.	Breakdown of Other Proceedings (Line 7, Col. 2 above)	Col. 2
10.	DSM	274.5
11.	CIS & Open Bill Consultatives	542.5
12.	Regulatory Cost Alloc Methodology Review ("RCAM")	91.1
13.	Consultation on Energy Issues / Low Income Consumers EB-2008-0150	12.1
14.	Total - Other proceedings	920.2

Witnesses: K. Culbert
R. Small

CLEARANCE OF 2011 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The Company is proposing to clear 2011 deferral and variance account balances to customers during the October 2012 billing cycle.

2. The unit rates for each type of service are shown at Exhibit C, Tab 2, Schedule 2, page 1. These unit rates will be applied to each customer's actual 2011 consumption volume for the period January 1, 2011 to December 31, 2011, and will be recovered or remitted in October 2012.

3. Exhibit C, Tab 2, Schedule 2 shows the derivation of the proposed unit rates:
   - Page 2 determines the balance (principal and interest) to be cleared for each Board-approved 2011 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 2011 consumption volumes for each rate class and each type of service.

4. The table on page 6 displays the bill adjustments in October 2012 for typical customers resulting from the clearance of the 2011 deferral and account balances. These bill adjustments will be shown as a separate line item on customers' October 2012 bills.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

Other:

5. The 2011 clearance will be the first time the Mean Daily Volume Mechanism Deferral Account ("MDVMDA") balance is cleared to customers. Development and implementation costs of the MDV re-establishment project have been tracked in the MDVMDA as per the Board's Decision in EB-2008-0106 Proceeding. Due to the capital nature of the project, the MDVMDA clears annual revenue requirements associated with the project spending of approximately $4.0 million. For this clearance, the revenue requirement amount is $616 thousand, as seen at Exhibit C, Tab 1, Schedule 1, page 2.

6. Given that the key features of the mechanism – weather normalized MDV and its re-establishment during the contract term – are calculated for each customer account separately and are primarily driven by the needs of general service customers (for example - pool composition change greater than the threshold can be triggered by drops, mid-term enrolments, vendor-to-vendor switches, migration from/to system gas, termination or reconnection of service, and change in customer location), it is proposed that the MDVMDA balance be allocated based on the number of customers by rate class. The proposed allocation treatment mirrors the proposal made in the evidence supporting the MDV settlement Agreement (EB-2008-0106, Exhibit MDV IR24, Schedule 4).

7. System gas and direct purchase customers within the same rate class will be applied the same unit rate. The proposed classification and allocation of the MDVMDA can be found at Exhibit C, Tab 2, Schedule 2, page 3.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

UNIT RATE AND TYPE OF SERVICE: CLEARING IN OCTOBER 2012

		COL.1
		TOTAL
		(¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	0.0170
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0922
	- WESTERN T-SERVICE	0.0170
RATE 6	- SYSTEM SALES	(0.2424)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.1672)
	- WESTERN T-SERVICE	(0.2424)
RATE 9	- SYSTEM SALES	(0.3415)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.2663)
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	0.7431
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.8183
	- WESTERN T-SERVICE	0.7431
RATE 110	- SYSTEM SALES	(0.0523)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0230
	- WESTERN T-SERVICE	(0.0523)
RATE 115	- SYSTEM SALES	(0.1787)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.1035)
	- WESTERN T-SERVICE	(0.1787)
RATE 135	- SYSTEM SALES	0.0893
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1645
	- WESTERN T-SERVICE	0.0893
RATE 145	- SYSTEM SALES	(0.4989)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.4237)
	- WESTERN T-SERVICE	(0.4989)
RATE 170	- SYSTEM SALES	0.0464
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1216
	- WESTERN T-SERVICE	0.0464
RATE 200	- SYSTEM SALES	(0.0484)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0268
	- WESTERN T-SERVICE	0.0000
Unbundled Services:		
RATE 125	- All	(1.8198)
	- Customer-specific ($)	$25,075
RATE 300	- All	(8.9873)

Witnesses: J. Collier
A. Kacicnik
M. Kirk

DETERMINATION OF BALANCES TO BE CLEARED
FROM THE 2011 DEFERRAL AND VARIANCE ACCOUNTS

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
1.	TRANSACTIONAL SERVICES D/A	(7,357.0)	(103.2)	(7,460.2)
2.	UNACCOUNTED FOR GAS V/A	8,536.2	87.5	8,623.7
3.	STORAGE AND TRANSPORTATION D/A	(910.0)	(15.3)	(925.3)
4.	DEFERRED REBATE ACCOUNT	(308.7)	(4.3)	(313.0)
5.	DEMAND SIDE MANAGEMENT 2010	(2,717.1)	(113.4)	(2,830.5)
6.	LOST REVENUE ADJ MECHANISM 2010	(42.9)	(0.5)	(43.4)
7.	SHARED SAVINGS MECHANISM 2010	4,155.3	25.5	4,180.8
8.	CLASS ACTION SUIT D/A	4,709.5	484.2	5,193.7
9.	ONTARIO HEARING COSTS V/A	(1,031.9)	(11.9)	(1,043.8)
10.	GAS DISTRIBUTION ACCESS RULE D/A	2,758.1	0.0	2,758.1
11.	AVERAGE USE TRUE-UP V/A	(2,948.9)	(32.4)	(2,981.3)
12.	ELECTRIC PROGRAM EARNINGS SHARING D/A	(247.5)	(2.7)	(250.2)
13.	UNBUNDLED RATE IMPLEMENTATION COST D/A	139.7	2.7	142.4
14.	MUNICIPAL PERMIT FEES D/A	429.4	0.0	429.4
15.	OPEN BILL SERVICE D/A	87.7	1.2	88.9
16.	OPEN BILL ACCESS V/A	79.4	1.1	80.5
17.	EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A	(234.4)	(2.7)	(237.1)
18.	TAX RATE & RULE CHANGE V/A	(1,200.0)	(18.1)	(1,218.1)
19.	MEAN DAILY VOLUME MECHANISM D/A	616.1	0.0	616.1
20.	EARNINGS SHARING MECHANISM	(14,300.0)	(155.6)	(14,455.6)
21.	TOTAL	(9,787.0)	142.1	(9,644.9)

Witnesses: J. Collier
A. Kacicnik
M. Kirk

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)
	CLASSIFICATION										
	PGVA:										
1.1	COMMODITY	0.0		0.0							
1.2	SEASONAL PEAKING-LOAD BALANCING	0.0					0.0				
1.3	SEASONAL DISCRETIONARY-LOAD BALANCING	0.0				0.0					
1.4	TRANSPORTATION TOLLS	0.0	0.0								
1.5	CURTAILMENT REVENUE	0.0					0.0		0.0		
1.6	RIDER C 2009 DIRECT ALLOCATION	0.0							0.0		
1.7	INVENTORY ADJUSTMENT	0.0									
1.		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.	**TRANSACTIONAL SERVICES D/A**	(7,460.2)	(5,665.1)			(859.7)	(935.5)				
2.	**UNACCOUNTED FOR GAS V/A**	8,623.7			8,623.7						
3.	**STORAGE AND TRANSPORTATION D/A**	(925.3)				(443.1)	(482.2)				
4.	**DEFERRED REBATE ACCOUNT**	(313.0)			(313.0)						
5.	**DEMAND SIDE MANAGEMENT 2010**	(2,830.5)							(2,830.5)		
6.	**LOST REVENUE ADJ MECHANISM 2010**	(43.4)							(43.4)		
7.	**SHARED SAVINGS MECHANISM 2010**	4,180.8							4,180.8		
8.	**CLASS ACTION SUIT D/A**	5,193.7								5,193.7	
9.	**ONTARIO HEARING COSTS V/A**	(1,043.8)									(1,043.8)
10.	**GAS DISTRIBUTION ACCESS RULE D/A**	2,758.1								2,758.1	
11.	**AVERAGE USE TRUE-UP V/A**	(2,981.3)							(2,981.3)		
12.	**ELECTRIC PROGRAM EARNINGS SHARING D/A**	(250.2)									(250.2)
13.	**UNBUNDLED RATE IMPLEMENTATION COST D/A**	142.4								142.4	
14.	**MUNICIPAL PERMIT FEES D/A**	429.4									429.4
15.	**OPEN BILL SERVICE D/A**	88.9								88.9	
16.	**OPEN BILL ACCESS V/A**	80.5								80.5	
17.	**EX-FRANCHISE THIRD PARTY BILLING SERVICES D/A**	(237.1)								(237.1)	
18.	**TAX RATE & RULE CHANGE V/A**	(1,218.1)									(1,218.1)
19.	**MEAN DAILY VOLUME MECHANISM D/A**	616.1								616.1	
20.	**EARNINGS SHARING MECHANISM**	(14,455.6)						(14,455.6)			
21.	**TOTAL**	(9,644.9)	(5,665.1)	0.0	8,310.7	(1,302.8)	(1,417.7)	(14,455.6)	(1,674.4)	8,642.6	(2,082.7)
	ALLOCATION										
1.1	RATE 1	1,346.8	(2,988.5)	0.0	3,404.5	(612.2)	(774.5)	(9,830.4)	5,749.8	7,816.0	(1,418.0)
1.2	RATE 6	(10,264.4)	(2,371.6)	0.0	3,419.1	(602.4)	(616.7)	(4,061.9)	(6,115.0)	682.2	(598.2)
1.3	RATE 9	(2.8)	(0.5)	0.0	0.6	(0.0)	0.0	(2.4)	0.0	0.0	(0.5)
1.4	RATE 100	81.4	(3.2)	0.0	7.5	(0.3)	(1.4)	(8.9)	86.8	2.2	(1.3)
1.5	RATE 110	33.0	(92.3)	0.0	395.6	(15.0)	(8.4)	(145.7)	(114.3)	30.4	(17.3)
1.6	RATE 115	(588.7)	(10.8)	0.0	404.6	0.0	(2.9)	(81.3)	(894.2)	4.2	(8.2)
1.7	RATE 125	(46.2)	0.0	0.0	0.0	0.0	0.0	(107.7)	0.0	75.8	(14.2)
1.8	RATE 135	80.8	(20.2)	0.0	44.5	0.0	0.0	(10.1)	61.3	6.2	(0.9)
1.9	RATE 145	(821.1)	(40.2)	0.0	133.5	(15.6)	0.0	(90.7)	(816.7)	18.7	(10.2)
1.10	RATE 170	593.8	(41.7)	0.0	378.6	(37.0)	0.0	(71.7)	367.9	5.5	(7.8)
1.11	RATE 200	(50.7)	(96.0)	0.0	122.2	(20.3)	(13.9)	(37.9)	0.0	0.1	(5.0)
1.12	RATE 300	(6.9)	0.0	0.0	0.0	0.0	0.0	(6.8)	0.0	1.2	(1.2)
1.		(9,644.9)	(5,665.1)	0.0	8,310.7	(1,302.8)	(1,417.7)	(14,455.6)	(1,674.4)	8,642.6	(2,082.7)

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
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	613.0	(2,709.3)	0.0	2,609.0	(469.2)	(593.5)	(7,533.5)	4,406.3	5,989.8	(1,086.7)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	670.5			526.6	(94.7)	(119.8)	(1,520.5)	889.3	1,208.9	(219.3)
	- WBT	63.2	(279.2)		268.9	(48.4)	(61.2)	(776.5)	454.1	617.3	(112.0)
RATE 6	- SYSTEM SALES	(5,632.4)	(1,747.5)	0.0	1,682.9	(296.5)	(303.5)	(1,999.2)	(3,009.8)	335.8	(294.4)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(2,620.7)			1,135.3	(200.0)	(204.8)	(1,348.7)	(2,030.4)	226.5	(198.6)
	- WBT	(2,011.3)	(624.0)		601.0	(105.9)	(108.4)	(713.9)	(1,074.8)	119.9	(105.1)
RATE 9	- SYSTEM SALES	(2.5)	(0.5)	0.0	0.5	(0.0)	0.0	(2.1)	0.0	0.0	(0.4)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(0.3)			0.1	(0.0)	0.0	(0.3)	0.0	0.0	(0.1)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	17.3	(1.8)	0.0	1.7	(0.1)	(0.3)	(2.0)	19.6	0.5	(0.3)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	49.8			4.4	(0.2)	(0.8)	(5.2)	51.0	1.3	(0.8)
	- WBT	14.3	(1.5)		1.4	(0.1)	(0.3)	(1.7)	16.2	0.4	(0.2)
RATE 110	- SYSTEM SALES	(34.8)	(50.1)	0.0	48.3	(1.8)	(1.0)	(17.8)	(13.9)	3.7	(2.1)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	97.2			306.7	(11.6)	(6.5)	(113.0)	(88.6)	23.6	(13.4)
	- WBT	(29.3)	(42.2)		40.6	(1.5)	(0.9)	(15.0)	(11.7)	3.1	(1.8)
RATE 115	- SYSTEM SALES	(0.1)	(0.0)	0.0	0.0	0.0	(0.0)	(0.0)	(0.1)	0.0	(0.0)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(563.1)			394.2	0.0	(2.8)	(79.2)	(871.3)	4.1	(8.0)
	- WBT	(25.5)	(10.7)		10.3	0.0	(0.1)	(2.1)	(22.8)	0.1	(0.2)
RATE 135	- SYSTEM SALES	1.3	(1.1)	0.0	1.0	0.0	0.0	(0.2)	1.4	0.1	(0.0)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	56.8			25.0	0.0	0.0	(5.7)	34.5	3.5	(0.5)
	- WBT	22.7	(19.2)		18.4	0.0	0.0	(4.2)	25.4	2.6	(0.4)
RATE 145	- SYSTEM SALES	(113.8)	(17.2)	0.0	16.5	(1.9)	0.0	(11.2)	(101.1)	2.3	(1.3)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(554.2)			94.8	(11.1)	0.0	(64.4)	(579.6)	13.3	(7.2)
	- WBT	(153.1)	(23.1)		22.2	(2.6)	0.0	(15.1)	(135.9)	3.1	(1.7)
RATE 170	- SYSTEM SALES	22.5	(36.5)	0.0	35.1	(3.4)	0.0	(6.7)	34.1	0.5	(0.7)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	568.1			338.4	(33.1)	0.0	(64.1)	328.8	4.9	(6.9)
	- WBT	3.2	(5.2)		5.0	(0.5)	0.0	(1.0)	4.9	0.1	(0.1)
RATE 200	- SYSTEM SALES	(61.8)	(96.0)	0.0	92.5	(15.3)	(10.5)	(28.7)	0.0	0.1	(3.8)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	11.0			29.7	(4.9)	(3.4)	(9.2)	0.0	0.0	(1.2)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		(46.2)	0.0	0.0	0.0	0.0	0.0	(107.7)	0.0	75.8	(14.2)
RATE 300		(6.9)	0.0	0.0	0.0	0.0	0.0	(6.8)	0.0	1.2	(1.2)
		(9,644.9)	(5,665.1)	0.0	8,310.7	(1,302.8)	(1,417.7)	(14,455.6)	(1,674.4)	8,642.6	(2,082.7)

Witnesses: J. Collier
A. Kacicnik
M. Kirk

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	NUMBER OF CUSTOMERS
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	($000/user)
Bundled Services:												
RATE 1	- SYSTEM SALES	0.0170	(0.0752)	0.0000	0.0724	(0.0130)	(0.0165)	(0.2092)	0.1223	0.1663	(0.0302)	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	0.0922	0.0000	0.0000	0.0724	(0.0130)	(0.0165)	(0.2092)	0.1223	0.1663	(0.0302)	0.0000
	- WESTERN T-SERVICE	0.0170	(0.0752)	0.0000	0.0724	(0.0130)	(0.0165)	(0.2092)	0.1223	0.1663	(0.0302)	0.0000
RATE 6	- SYSTEM SALES	(0.2424)	(0.0752)	0.0000	0.0724	(0.0128)	(0.0131)	(0.0861)	(0.1296)	0.0145	(0.0127)	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	(0.1672)	0.0000	0.0000	0.0724	(0.0128)	(0.0131)	(0.0861)	(0.1296)	0.0145	(0.0127)	0.0000
	- WESTERN T-SERVICE	(0.2424)	(0.0752)	0.0000	0.0724	(0.0128)	(0.0131)	(0.0861)	(0.1296)	0.0145	(0.0127)	0.0000
RATE 9	- SYSTEM SALES	(0.3415)	(0.0752)	0.0000	0.0724	(0.0020)	0.0000	(0.2852)	0.0000	0.0057	(0.0572)	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	(0.2663)	0.0000	0.0000	0.0724	(0.0020)	0.0000	(0.2852)	0.0000	0.0057	(0.0572)	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.7431	(0.0752)	0.0000	0.0724	(0.0032)	(0.0131)	(0.0861)	0.8393	0.0215	(0.0127)	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	0.8183	0.0000	0.0000	0.0724	(0.0032)	(0.0131)	(0.0861)	0.8393	0.0215	(0.0127)	0.0000
	- WESTERN T-SERVICE	0.7431	(0.0752)	0.0000	0.0724	(0.0032)	(0.0131)	(0.0861)	0.8393	0.0215	(0.0127)	0.0000
RATE 110	- SYSTEM SALES	(0.0523)	(0.0752)	0.0000	0.0724	(0.0027)	(0.0015)	(0.0267)	(0.0209)	0.0056	(0.0032)	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	0.0230	0.0000	0.0000	0.0724	(0.0027)	(0.0015)	(0.0267)	(0.0209)	0.0056	(0.0032)	0.0000
	- WESTERN T-SERVICE	(0.0523)	(0.0752)	0.0000	0.0724	(0.0027)	(0.0015)	(0.0267)	(0.0209)	0.0056	(0.0032)	0.0000
RATE 115	- SYSTEM SALES	(0.1787)	(0.0752)	0.0000	0.0724	0.0000	(0.0005)	(0.0146)	(0.1601)	0.0007	(0.0015)	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	(0.1035)	0.0000	0.0000	0.0724	0.0000	(0.0005)	(0.0146)	(0.1601)	0.0007	(0.0015)	0.0000
	- WESTERN T-SERVICE	(0.1787)	(0.0752)	0.0000	0.0724	0.0000	(0.0005)	(0.0146)	(0.1601)	0.0007	(0.0015)	0.0000
RATE 135	- SYSTEM SALES	0.0893	(0.0752)	0.0000	0.0724	0.0000	0.0000	(0.0165)	0.0998	0.0102	(0.0014)	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	0.1645	0.0000	0.0000	0.0724	0.0000	0.0000	(0.0165)	0.0998	0.0102	(0.0014)	0.0000
	- WESTERN T-SERVICE	0.0893	(0.0752)	0.0000	0.0724	0.0000	0.0000	(0.0165)	0.0998	0.0102	(0.0014)	0.0000
RATE 145	- SYSTEM SALES	(0.4989)	(0.0752)	0.0000	0.0724	(0.0085)	0.0000	(0.0492)	(0.4431)	0.0102	(0.0055)	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	(0.4237)	0.0000	0.0000	0.0724	(0.0085)	0.0000	(0.0492)	(0.4431)	0.0102	(0.0055)	0.0000
	- WESTERN T-SERVICE	(0.4989)	(0.0752)	0.0000	0.0724	(0.0085)	0.0000	(0.0492)	(0.4431)	0.0102	(0.0055)	0.0000
RATE 170	- SYSTEM SALES	0.0464	(0.0752)	0.0000	0.0724	(0.0071)	0.0000	(0.0137)	0.0704	0.0011	(0.0015)	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	0.1216	0.0000	0.0000	0.0724	(0.0071)	0.0000	(0.0137)	0.0704	0.0011	(0.0015)	0.0000
	- WESTERN T-SERVICE	0.0464	(0.0752)	0.0000	0.0724	(0.0071)	0.0000	(0.0137)	0.0704	0.0011	(0.0015)	0.0000
RATE 200	- SYSTEM SALES	(0.0484)	(0.0752)	0.0000	0.0724	(0.0120)	(0.0082)	(0.0225)	0.0000	0.0001	(0.0030)	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	0.0268	0.0000	0.0000	0.0724	(0.0120)	(0.0082)	(0.0225)	0.0000	0.0001	(0.0030)	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:												
RATE 125	- All	(1.8198)	0.0000	0.0000	0.0000	0.0000	0.0000	(1.6149)	0.0000	0.0086	(0.2136)	0.0000
	- Customer-specific **											25.0751
RATE 300	- All	(8.9873)	0.0000	0.0000	0.0000	0.0000	0.0000	(8.9331)	0.0000	1.5097	(1.5639)	0.0000

Notes:
* Unit Rates derived based on 2011 actual volumes
** The Company incurred $75.2 k in additional staffing costs in 2011 associated with the additional upstream (such as FT-SN) nomination windows for unbundled customers. As specified in the NGEIR Settlement Agreement (EB-2005-0551 Ex S T1 S1 p13), the costs are to be recovered from the parties who availed of the service. Three customers on Rate 125 utilized the additional nomination windows in 2011 and the costs were allocated equally among the three customers.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

Enbridge Gas Distribution Inc.
2011 Deferral and Variance Account Clearing
Bill Adjustment in October 2012 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	0.0170	0.0922	0.0170	0.5	2.8	0.5
2.1	**RATE 6 COMMERCIAL**							
2.2	General Use	43,285	(0.2424)	(0.1672)	(0.2424)	(105)	(72)	(105)
	CONTRACT SERVICE							
3.1	**RATE 100**							
3.2	Industrial - small size	339,188	0.7431	0.8183	0.7431	2,520	2,776	2,520
4.1	**RATE 110**							
4.2	Industrial - small size, 50% LF	598,568	(0.0523)	0.0230	(0.0523)	(313)	137	(313)
4.5	Industrial - avg. size, 75% LF	9,976,120	(0.0523)	0.0230	(0.0523)	(5,215)	2,290	(5,215)
5.1	**RATE 115**							
5.2	Industrial - small size, 80% LF	4,471,609	(0.1787)	(0.1035)	(0.1787)	(7,990)	(4,627)	(7,990)
6.1	**RATE 135**							
6.2	Industrial - Seasonal Firm	598,567	0.0893	0.1645	0.0893	534	985	534
7.1	**RATE 145**							
7.2	Commercial - avg. size	598,568	(0.4989)	(0.4237)	(0.4989)	(2,986)	(2,536)	(2,986)
8.1	**RATE 170**							
8.2	Industrial - avg. size, 75% LF	9,976,120	0.0464	0.1216	0.0464	4,627	12,131	4,627

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

Witnesses: J. Collier
A. Kacicnik
M. Kirk

ENBRIDGE GAS DISTRIBUTION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2011

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) 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 Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC 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 AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

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

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

(Signed)

D. Guy Jarvis
President, Gas Distribution

(Signed)

Narinder K. Kishinchandani
Vice President, Finance

February 14, 2012

February 14, 2012

Independent Auditor's Report

To the Shareholders of Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2011 and 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2011 and 2010 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants

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CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Gas commodity and distribution revenue *(Note 20)*	**2,010**	1,977
Transportation of gas for customers	**352**	390
	2,362	2,367
Gas commodity and distribution costs excluding depreciation *(Note 20)*	**(1,341)**	(1,372)
Gas distribution margin	**1,021**	995
Other revenue	**104**	108
	1,125	1,103
Expenses		
Operating and administrative *(Note 20)*	**419**	393
Depreciation and amortization	**281**	270
Municipal and other taxes	**41**	44
Earnings sharing *(Note 3)*	**13**	19
	754	726
	371	377
Affiliate financing income *(Note 20)*	**63**	63
Interest expense *(Notes 10 and 20)*	**(172)**	(186)
	262	254
Income taxes *(Note 17)*		
Current	**(50)**	(59)
Future	**(1)**	(2)
	(51)	(61)
Earnings	**211**	193
Preferred share dividends	**(2)**	(2)
Earnings attributable to the common shareholder	**209**	191

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Earnings	**211**	193
Other comprehensive income/(loss)		
Change in unrealized loss on cash flow hedges, net of tax	**(1)**	(17)
Reclassification to earnings of realized gains on cash flow hedges, net of tax	**2**	2
Change in foreign currency translation adjustment	**-**	(1)
Other comprehensive income/(loss)	**1**	(16)
Comprehensive income	**212**	177

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Preferred shares *(Note 12)*	**100**	100
Common shares *(Note 12)*		
Balance at beginning of year	**1,071**	1,071
Common shares issued	**66**	-
Balance at end of year	**1,137**	1,071
Contributed surplus	**202**	202
Retained earnings		
Balance at beginning of year	**572**	596
Earnings attributable to the common shareholder	**209**	191
Common share dividends declared	**(220)**	(215)
Balance at end of year	**561**	572
Accumulated other comprehensive loss		
Balance at beginning of year	**(18)**	(2)
Other comprehensive income	**1**	(16)
Balance at end of year	**(17)**	(18)
Total shareholders' equity	**1,983**	1,927

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating activities		
Earnings	**211**	193
Depreciation and amortization	**281**	270
Future income taxes	**1**	2
Other	**4**	2
Changes in operating assets and liabilities *(Note 19)*	**17**	45
	514	512
Investing activities		
Additions to property, plant and equipment	**(441)**	(345)
Additions to intangible assets	**(34)**	(20)
Change in construction payable	**5**	-
Other	**6**	-
	(464)	(365)
Financing activities		
Change in bank overdraft	**(10)**	(11)
Net change in short-term borrowings	**222**	(182)
Issue of short-term note payable to affiliate company *(Note 20)*	**5**	2
Repayment of short-term note payable to affiliate company *(Note 20)*	**(3)**	(3)
Debenture and term note issues	**100**	402
Debenture and term note repayments	**(150)**	(150)
Preferred share dividends	**(2)**	(2)
Common share dividends	**(218)**	(208)
Other	**2**	(2)
	(54)	(154)
Decrease in cash and cash equivalents	**(4)**	(7)
Cash and cash equivalents at beginning of year	**13**	20
Cash and cash equivalents at end of year	**9**	13
Supplementary cash flow information		
Income taxes paid	**62**	59
Interest paid *(Note 10)*	**169**	185

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2011**	2010
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**9**	13
Accounts receivable and other *(Notes 5 and 20)*	**663**	802
Gas inventories	**380**	400
	1,052	1,215
Property, plant and equipment, net *(Note 6)*	**4,770**	4,458
Investment in affiliate company *(Note 20)*	**825**	825
Deferred amounts and other assets *(Note 7)*	**489**	487
Intangible assets *(Note 8)*	**179**	167
	7,315	7,152
Liabilities and shareholders' equity		
Current liabilities		
Bank overdraft	**7**	17
Short-term borrowings *(Note 10)*	**556**	332
Accounts payable and other *(Notes 9 and 20)*	**713**	850
Current maturities of long-term debt *(Note 10)*	**-**	150
Future income taxes *(Note 17)*	**2**	5
	1,278	1,354
Long-term debt *(Note 10)*	**2,374**	2,267
Other long-term liabilities *(Note 11)*	**1,127**	1,058
Future income taxes *(Note 17)*	**178**	171
Loans from affiliate company *(Notes 10 and 20)*	**375**	375
	5,332	5,225
Shareholders' equity		
Share capital		
Preferred shares *(Note 12)*	**100**	100
Common shares *(Note 12)*	**1,137**	1,071
Contributed surplus	**202**	202
Retained earnings	**561**	572
Accumulated other comprehensive loss	**(17)**	(18)
	1,983	1,927
Commitments and contingencies *(Notes 20 and 21)*		
	7,315	7,152

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

Approved by the Board of Directors:

(Signed)

D. Guy Jarvis
President

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

The Company also owns and operates unregulated facilities in Ontario, including two solar projects located in Amherstburg, Ontario, through its 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg) and unregulated natural gas storage facilities.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of the consolidated financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 3)*; unbilled revenues *(Note 5)*; allowance for doubtful accounts *(Note 5)*; depreciation rates and carrying values of property, plant and equipment *(Note 6)*; amortization rates and carrying values of intangible assets *(Note 8)*; fair values of financial instruments *(Notes 14 and 15)*; income taxes *(Note 17)*; post-employment benefits *(Note 18);* contingencies *(Note 21);* and fair value of asset retirement obligations. Actual results could differ from those estimates.

BASIS OF PRESENTATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments are accounted for according to their classification (see Financial Instruments). All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION

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

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

REVENUE RECOGNITION

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

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

FINANCIAL INSTRUMENTS

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

Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings. The Company has classified Cash and cash equivalents and Bank overdraft as held for trading.

Available for Sale

The Company classifies its investment in the preferred shares of IPL System Inc. as an available for sale financial asset. Available for sale 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. This investment originated in a related party transaction. No external market for the instrument exists and no quoted market price is available in an active market. Therefore, the invesment is carried at cost and a fair value has not been determined. Dividends received from this investment are recognized in earnings when the right to receive payment is established *(Note 20)*.

Loans and Receivables

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

Other Financial Liabilities

Other financial liabilities are measured at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Long-term debt and Loans from affiliate company.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes in natural gas prices and interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges outstanding as at December 31, 2011 and 2010.

Cash Flow Hedges

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

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

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

Balance Sheet Offset

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

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

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

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

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

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

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

At December 31, 2011, $100 million of natural gas was held on behalf of transportation service customers (December 31, 2010 - $102 million). These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment are recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates approved by the Regulators.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS

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

INTANGIBLE ASSETS

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

ASSET RETIREMENT OBLIGATIONS

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

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

POST-EMPLOYMENT BENEFITS

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

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

- The cost of pensions and OPEB earned by employees are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and expected health-care and insurance costs. 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.
- Pension plan assets are measured at fair value.
- The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
- The excess of the cumulative unrecognized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets is amortized over the expected average remaining service lives of the active employee group covered by the plans.
- The transitional asset and obligation is amortized over the expected average remaining service period of the active employee group covered by the plans at the date of transition. The transitional asset relates to the pension plans and is the fair value of the plan assets less the accrued benefit obligation at October 1, 2000, amortized over 13 years. The transitional obligation relates to OPEB and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The regulated utility operations of the Company recover pension and OPEB expense based on the amounts paid. This is in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator approved future rates and recovered from, or refunded to, future customers.

COMPARATIVE AMOUNTS

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

2. CHANGES IN ACCOUNTING POLICIES

Business Combinations

Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations,* which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings, cash flows, or financial position for the year ended December 31, 2011.

Consolidated Financial Statements and Noncontrolling Interests

Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and non controlling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings, cash flows, or financial position for the current or prior periods presented.

United States Generally Accepted Accounting Principles (U.S. GAAP)

First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of The CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has presented its consolidated financial statements in accordance with Part V of The CICA Handbook in the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business and performance measurement. The Company believes U.S. GAAP, which articulates specific guidance for entities subject to rate regulation, provides a more relevant basis on which to evaluate and present its regulated businesses. As a wholly-owned subsidiary of a United States Securities and Exchange Commission (SEC) registrant, the Company has received permission from the Canadian securities regulators to prepare its consolidated financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual consolidated financial statements beginning on January 1, 2012.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

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

RATE APPROVAL

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

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

APPROVED RATES

Enbridge Gas Distribution

Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2011 (2010 - 8.39%) based on a 36% (2010 - 36%) deemed common equity component of capital for regulatory purposes.

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

St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2011 (2010 - 10.5%) based on a 50% (2010 - 50%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11% (2010 - 11%) are shared equally with customers. The calculation of such earnings is cumulative over the three-year period commencing January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact for the years ended December 31, 2011 and December 31, 2010.

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. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

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

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2011**	2010	Consolidated Statements of Financial Position Classification**	Estimated Recovery/ Settlement Period *(years)*	Earnings Impact[1] **2011**	Earnings Impact[1] 2010
(millions of Canadian dollars)						
Regulatory Assets/(Liabilities)						
Enbridge Gas Distribution						
Future income taxes [2]	**164**	164	DA/OLTL	*	**-**	(7)
OPEB [3]	**74**	68	DA	*	**4**	4
Unaccounted for gas variance [4]	**9**	18	AR	1	**(7)**	5
Settlement recoverable [5]	**5**	15	AR	1	**(7)**	(3)
Deferred rate hearing costs [6]	**3**	3	AR/DA	2	**-**	(2)
Future removal and site restoration reserves [7]	**(815)**	(753)	OLTL	*	**-**	-
Pension plans [8]	**(231)**	(222)	OLTL	*	**(6)**	(6)
Transactional services deferral [9]	**(7)**	(14)	AP	1	**-**	-
Earnings sharing deferral [10]	**(14)**	(38)	AP	1	**-**	-
Average use true-up variance [11]	**(3)**	4	AP/AR	*	**(5)**	1
Purchased gas variance [12]	**-**	(144)	AP	1	**-**	-
Shared Savings Mechanism [13]	**-**	11	AR	*	**-**	-
Other regulatory assets and liabilities	**2**	10	***	*	**(4)**	-
	(813)	(878)			**(25)**	(8)
St. Lawrence						
Other regulatory assets and liabilities	**6**	3	***	*	**2**	3
	6	3			**2**	3
	(807)	(875)			**(23)**	(5)

* Refer to the footnote for details.

**

AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

*** Dependent on the nature of the item.

1. *The earnings impact represents the increase/(decrease) in the Company's after-tax reported earnings as a result of the rate regulated recognition of the item, excluding any additional earnings sharing impact. This includes the impact of items outstanding at the end of the prior year being recovered or refunded in the current year.*

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

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

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

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

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

7. *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*
8. *The pension plans' balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover pension expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would be charged to earnings based on the accrual basis of accounting.*
9. *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*
10. *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized earnings (i.e., excluding the effects of weather) represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2011 balance relates to the years ended December 31, 2011 and 2010. The December 31, 2010 balance relates to the years ended December 31, 2010 and 2009. There would be no change in the treatment of this item in the absence of rate regulation.*
11. *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*
12. *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the following quarter via the Quarterly Rate Adjustment Mechanism (QRAM) process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*
13. *Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

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

Operating Cost Capitalization

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

The Company entered into a service contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, costs relating to this service contract of $133 million (2010 - $124 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

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

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2011, the net book value of these costs was $99 million (2010 - $111 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories

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

Included in gas inventories at December 31, 2011 is $42 million (2010 - $43 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred.

Depreciation

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

4. ACQUISITION

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. Project Amherstburg holds two solar projects, consisting of separate 10 megawatt (MW) and 5-MW facilities, both located in Amherstburg, Ontario. The total consideration transferred for the two projects was approximately $66 million, and was primarily funded by the issuance of common shares (1,612,367 shares). The remaining 0.1% limited partnership interest is owned by the general partner, Project AMBG2 Inc., a wholly-owned subsidiary of Enbridge Inc.

The transaction, which is a related party transaction, has been accounted for at carrying value. The Company consolidates its interest in Project Amherstburg.

Since the acquisition date, Project Amherstburg's revenue and earnings before tax for the year ended December 31, 2011 were $3 million and $2 million, respectively.

December 31,	**2011**
(millions of Canadian dollars)	
Carrying value of assets acquired:	
Property, plant and equipment	59
Intangible assets	9
Future income tax liability	(2)
	66
Consideration:	
Common shares	66

5. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Trade receivables	**378**	422
Unbilled revenues	**175**	231
Agent billing and collection receivable	**69**	86
Regulatory assets *(Note 3)*	**24**	61
Due from affiliates *(Note 20)*	**12**	11
Taxes receivable	**22**	14
Prepaid expenses	**3**	5
Other	**25**	23
Allowance for doubtful accounts	**(45)**	(51)
	663	802

6. PROPERTY, PLANT AND EQUIPMENT

December 31, 2011	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Regulated property, plant and equipment				
Gas mains	**4.2%**	**2,641**	**528**	**2,113**
Gas services	**4.5%**	**2,120**	**667**	**1,453**
Regulating and metering equipment	**3.7%**	**719**	**236**	**483**
Gas storage	**3.0%**	**275**	**89**	**186**
Land and right-of-way	**2.5%**	**79**	**30**	**49**
Computer technology	**19.8%**	**35**	**5**	**30**
Under construction	**-**	**92**	**-**	**92**
Construction materials inventory	**-**	**39**	**-**	**39**
Other	**3.5%**	**259**	**76**	**183**
		6,259	**1,631**	**4,628**
Unregulated property, plant and equipment				
Gas storage	**3.0%**	**88**	**4**	**84**
Solar assets	**4.0%**	**59**	**1**	**58**
		147	**5**	**142**
		6,406	**1,636**	**4,770**

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Regulated property, plant and equipment				
Gas mains	4.2%	2,505	484	2,021
Gas services	4.6%	2,036	628	1,408
Regulating and metering equipment	3.8%	691	224	467
Gas storage	2.8%	240	79	161
Land and right-of-way	2.6%	77	29	48
Computer technology	19.8%	33	4	29
Under construction	-	66	-	66
Construction materials inventory	-	25	-	25
Other	3.5%	259	76	183
		5,932	1,524	4,408
Unregulated property, plant and equipment				
Gas storage	3.0%	52	2	50
		52	2	50
		5,984	1,526	4,458

Total depreciation expense, including amounts collected for future removal and site restoration costs, for property, plant and equipment was $250 million for the year ended December 31, 2011 (2010 - $238 million).

7. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory assets *(Note 3)*	**248**	252
Pension asset *(Note 18)*	**231**	222
Other	**10**	13
	489	487

8. INTANGIBLE ASSETS

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Regulated intangible assets				
Software	**20.0%**	**111**	**40**	**71**
CIS	**10.1%**	**127**	**28**	**99**
		238	**68**	**170**
Unregulated intangible assets				
Power purchase contract	**5.0%**	**9**	**-**	**9**
		9	**-**	**9**
		247	**68**	**179**

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

Intangible assets include $21 million of work-in-progress for the year ended December 31, 2011 (2010 - $9 million). Total amortization expense for intangible assets was $31 million for the year ended December 31, 2011 (2010 - $32 million).

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating accrued liabilities	**250**	282
Regulatory liabilities *(Note 3)*	**32**	204
Budget billing plan payable	**136**	92
Security deposits	**79**	73
Dividends payable	**56**	54
Trade payables	**67**	57
Taxes payable	**26**	34
Interest payable	**26**	29
Due to affiliates *(Note 20)*	**10**	3
Current derivative liabilities *(Note 15)*	**1**	1
Other	**30**	21
	713	850

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2011**	2010
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	235
Medium term notes	5.51%	2014-2050	**2,295**	2,195
Commercial paper and credit facility draws, net			**555**	333
Other			**8**	6
Deferred debt issue costs			**(13)**	(20)
Total debt			**2,930**	2,749
Current maturities			**-**	(150)
Short-term borrowings	1.07%		**(556)**	(332)
Long-term debt			**2,374**	2,267
Loans from affiliate company			**375**	375

Medium term note maturities for the years ending December 31, 2012 through 2016 are nil, nil, $400 million, nil, and nil, respectively. The Company's debenture and medium term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $135 million, $135 million, $129 million, $114 million and $114 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Debenture and medium term notes	**140**	149
Loans from affiliate company *(Note 20)*	**27**	27
Commercial paper and credit facility draws	**3**	2
Other interest and finance costs	**8**	11
Capitalized	**(6)**	(3)
	172	186

In 2011, total interest paid to third parties was $149 million (2010 - $158 million) and total interest paid to affiliated companies was $20 million (2010 - $27 million).

CREDIT FACILITIES

The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

December 31, 2011	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	**700**	**545**	**155**
St. Lawrence Gas Company, Inc.	**12**	**10**	**2**
Total credit facilities	**712**	**555**	**157**

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

Credit facilities carried a weighted average standby fee of 0.38% per annum from January to July 2011 and 0.22% per annum from August to December 2011 on the unused portion and draws bear interest at market rates.

11. OTHER LONG-TERM LIABILITIES

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory liabilities *(Note 3)*	**1,047**	984
OPEB liabilities *(Note 18)*	**75**	71
Pension liability *(Note 18)*	**5**	3
	1,127	1,058

12. SHARE CAPITAL

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

COMMON SHARES

December 31,	**2011**		2010	
	Number of Shares	**Amount**	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Balance at beginning of year	**140.7**	**1,071**	140.7	1,071
Common shares issued	**1.6**	**66**	-	-
Balance at end of year	**142.3**	**1,137**	140.7	1,071

PREFERRED SHARES

December 31, 2011 and 2010	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preferred shares in millions)			
Group 1	0.2	nil	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	nil	-
Group 2, Series D, Cumulative Redeemable Convertible	4	nil	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	nil	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	nil	-
Group 5	10	nil	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

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

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

13. STOCK OPTION AND STOCK UNIT PLANS

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

INCENTIVE STOCK OPTIONS

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

During the year ended December 31, 2011, 663,800 stock options (2010 - 361,000 stock options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $28.78 in 2011 (2010 - $23.30) and a grant date fair value of $4.00 (2010 - $3.28).

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan that includes the Company’s senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge’s weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge’s performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2009, 2010, and 2011 grants derive the performance multiplier through a calculation of Enbridge’s price/earnings ratio relative to a specified peer group of companies and Enbridge’s growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

During the year ended December 31, 2011, 25,200 PSUs (2010 - 18,200) were issued to employees of the Company.

RESTRICTED STOCK UNITS

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

During the year ended December 31, 2011, Enbridge granted 111,300 RSUs (2010 - 124,000) to certain employees of the Company.

STOCK-BASED COMPENSATION EXPENSE

The Company is charged an expense for stock-based compensation which includes a direct charge for ISOs, PSUs and RSUs issued to employees of the Company and an allocation of such costs with respect to employees of Enbridge who provide services to the Company. For the year ended December 31, 2011, the total amount of direct charge was $8 million (2010 - $6 million) and the total amount of allocation was $6 million (2010 - $5 million). These costs are included in operating and administrative expenses.

14. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

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

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

Interest Rate Risk

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

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 - nil) in earnings and would have caused a $1 million increase (2010 - $3 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011, and a $6 million decrease (2010 - $3 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2010 - nil).

Natural Gas Price Risk

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

TOTAL DERIVATIVE INSTRUMENTS

The total notional principal or quantity outstanding related to the Company's derivative instruments at December 31, 2011 include $111 million of interest rate contracts and 6 million cubic metres of natural gas contracts, both maturing in 2012.

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

The Company estimates that $1 million of AOCL related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. Any gains or losses from natural gas derivatives are borne by customers. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months at December 31, 2011.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 20 and 21)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations and the issuance of commercial paper and/or credit facility draws. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 10)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt and loans from affiliate company *(Notes 10 and 20)*.

Based on valuations at December 31, 2011, the Company's financial derivative instruments will give rise to $1 million undiscounted cash outflows in 2012.

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 15, *Fair Value of Financial Instruments*.

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

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Balance at beginning of year	**(51)**	**(57)**
Additional allowance	**(25)**	**(23)**
Amounts used and reversed	**31**	**29**
Balance at end of year	**(45)**	**(51)**

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

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

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

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

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with those specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011, the Company has a maximum exposure to credit risk of nil (2010 - nil) related to its derivative counterparties.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

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

December 31, 2011	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	9	-	-	-	-	-	9	9
Accounts receivable and other	-	-	614	-	-	49	663	614
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	7	-	-	-	-	-	7	7
Short-term borrowings	-	-	-	556	-	-	556	556
Accounts payable and other	-	-	-	654	1	58	713	655
Long-term debt	-	-	-	2,374	-	-	2,374	2,943
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	13	-	-	-	-	-	13	13
Accounts receivable and other	-	-	722	-	-	80	802	722
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	17	-	-	-	-	-	17	17
Short-term borrowings	-	-	-	332	-	-	332	332
Accounts payable and other	-	-	-	611	1	238	850	612
Long-term debt	-	-	-	2,417	-	-	2,417	2,775
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

1. *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market (Note 20).*
2. *Investment in affiliate company and loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined (Note 20).*

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

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

FAIR VALUE OF DERIVATIVES

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

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

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

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

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

At December 31, 2011, the Company has current Level 2 derivative liabilities with fair value of $1 million (2010 - $1 million).

16. CAPITAL DISCLOSURES

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

The Company's capital is calculated as follows:

December 31,	**2011**	2010
(millions of Canadian dollars)		
Cash and cash equivalents	**(9)**	(13)
Bank overdraft	**7**	17
Short-term borrowings	**556**	332
Long-term debt (includes current portion)	**2,387**	2,437
Loans from affiliate company	**375**	375
Shareholders' equity	**2,000**	1,945
	5,316	5,093

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

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

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

The Company’s borrowings, whether debentures or medium term notes, are unsecured. When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company’s trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as Canadian GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of debt issue costs and intercompany interest expense, less gains on asset dispositions divided by the annual interest requirements. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2011, the Company was in compliance with these covenants.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Earnings before income taxes	**262**	254
Combined statutory income tax rate	**28.3%**	31.0%
Income taxes at statutory rate	**74**	79
Increase/(decrease) resulting from:		
Non-taxable dividend income from affiliated companies	**(18)**	(19)
Future income taxes related to regulated operations	**-**	7
Other	**(5)**	(6)
Income taxes	**51**	61
Effective income tax rate	**19.5%**	24.0%

The future income taxes recorded in current liabilities of $2 million (2010 - $5 million) arise primarily from temporary differences relating to regulatory deferral accounts.

At December 31, 2011, the Company had a future income tax liability of $164 million (2010 - $164 million) related to regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset *(Note 3)* to the extent that the future income tax liability is expected to be included in regulator-approved future rates and recovered from future customers.

18. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company provides a non-contributory basic pension plan that provides either defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans which provide pension benefits in excess of the basic plan for certain employees. A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation.

Defined Benefit Plans
Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recent actuarial valuation was December 31, 2009, and the effective date of the next required actuarial valuation is December 31, 2012.

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

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

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

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

	Pension Benefits		OPEB	
December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**702**	588	**87**	81
Service cost	**16**	12	**1**	1
Interest cost	**39**	39	**5**	5
Actuarial loss	**127**	79	**13**	5
Benefits paid	**(33)**	(31)	**(3)**	(3)
Other	**1**	15	**-**	(2)
Benefit obligation at end of year	**852**	702	**103**	87
Change in plan assets				
Fair value of plan assets at beginning of year	**759**	695	**4**	-
Transfer to the defined contribution component	**(1)**	(2)	**-**	-
Actual return on plan assets	**15**	78	**-**	-
Employer's contributions	**4**	4	**6**	7
Benefits paid	**(33)**	(31)	**(3)**	(3)
Other	**-**	15	**(1)**	-
Fair value of plan assets at end of year	**744**	759	**6**	4
Funded status				
Benefit obligation	**(852)**	(702)	**(103)**	(87)
Fair value of plan assets	**744**	759	**6**	4
Overfunded/(underfunded) status at end of year	**(108)**	57	**(97)**	(83)
Unamortized prior service cost	**2**	4	**-**	-
Unamortized transitional (asset)/obligation	**(44)**	(70)	**13**	16
Unamortized net actuarial loss/(gain)	**376**	228	**9**	(4)
Net amount recognized in the Consolidated Statements of Financial Position at end of year	**226**	219	**(75)**	(71)
Included in the following accounts:				
Deferred amounts and other assets *(Note 7)*	**231**	222	**-**	-
Other long-term liabilities *(Note11)*	**(5)**	(3)	**(75)**	(71)

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

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Discount rate	**4.50%**	5.70%	**4.50%**	5.70%
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	**5.00%**

Net Benefit Costs Recognized

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Benefits earned during the year	**16**	12	**1**	1
Interest cost on projected benefit obligations	**39**	39	**5**	5
Actual return on plan assets	**(15)**	(78)	**-**	-
Actuarial loss	**127**	79	**13**	5
Differences between costs arising in the year and costs recognized in the year:				
Return on plan assets	**(38)**	29	**-**	-
Prior service costs	**2**	1	**-**	-
Transitional (asset)/obligation	**(26)**	(24)	**3**	3
Actuarial loss	**(110)**	(64)	**(13)**	(5)
Net defined benefit costs on an accrual basis	**(5)**	(6)	**9**	9
Defined contribution benefit costs	**1**	2	**-**	-
(Credits)/costs on an accrual basis	**(4)**	(4)	**9**	9

Costs related to the period on an accrual basis are presented above and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense, which is consistent with the recovery of such costs in rates, was $4 million for pension benefits and $4 million for OPEB for the year ended December 31, 2011 (2010 - $4 million and $4 million, respectively).

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

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Discount rate	**5.70%**	6.60%	**5.70%**	6.60%
Average rate of return on pension plan assets	**7.25%**	7.14%	**-**	-
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	5.00%

MEDICAL COST TRENDS

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

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	8.40%	4.50%	2029
Other Medical and Dental	4.50%	4.50%	2029

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $15 million in the accumulated post-employment benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $12 million in the accumulated post-employment benefit obligations and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

Major Categories of Plan Assets

	Pension Benefits		
	2011		2010
As at December 31,	Allocation	Amount	Allocation
(millions of Canadian dollars)			
Equity securities	**55%**	**410**	58%
Fixed income securities	**44%**	**328**	41%
Other	**1%**	**7**	1%
Total assets	**100%**	**745**	100%

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

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

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Total contributions	**4**	4	**6**	7
Contributions expected to be paid in 2012	**20**		**4**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2012	2013	2014	2015	2016	2017-2021
(millions of Canadian dollars)						
Expected future benefit payments	39	41	43	45	47	255

19. CASH FLOW INFORMATION

CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Accounts receivable and other	**139**	8
Gas inventories	**20**	(4)
Accounts payable and other	**(142)**	41
	17	45

SIGNIFICANT NON-CASH ITEMS

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares.

20. RELATED PARTY TRANSACTIONS

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
IPL System Inc.		
Dividend income	**63**	63
Interest expense	**27**	27
Enbridge Inc.		
Purchase of treasury and other management services	**34**	32
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**28**	30
Vector Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**24**	27
Vector Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**2**	1
Alliance Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**25**	25
Alliance Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**18**	17
Enbridge Commercial Services Inc.		
Purchase of information services	**-**	2

The Company had related party balances as follows:

December 31,	**2011**	2010
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**9**	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	**8**	6
Accounts receivables/(payables)		
Enbridge Inc.	**(1)**	(1)
Gazifère Inc.	**4**	5
Niagara Gas Transmission Ltd.	**2**	-

Financing Transactions

The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2011, the investment of $825 million (2010 - $825 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2011, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2011, interest paid amounted to $20 million (2010 - $27 million).

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

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

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

Gas Transportation Services
The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2012 - $69 million, 2013 to 2014 - $131 million, 2015 to 2016 - $70 million and thereafter - nil.

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

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

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

Other Transactions
In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares *(Note 4)*.

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

21. COMMITMENTS AND CONTINGENCIES

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

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Services contract [1]	15	7	8	-	-
Customer care service contracts [2]	359	58	115	122	64
Total	374	65	123	122	64

1. *Primarily 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, 2011, $133 million (2010 - $124 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*
2. *In 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites

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

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

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

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

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2012 fiscal years, the OEB approved the establishment of deferral accounts. The issue of whether the possible claims and related costs are recoverable from customers has yet to be determined.

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

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

Bloor Street Incident

The Company was 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 in April 2003 on Bloor Street West in Toronto. In December 2011, the Company pleaded guilty before the Ontario Court of Justice to one charge under OHSA and one charge under TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by the Company was $875,000.

OTHER LITIGATON

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

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debenture
9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal, Calgary and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

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

TRUSTEE

Medium Term Notes
CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

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

CORPORATE GOVERNANCE

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

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

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

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

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

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

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

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 2, 2011), which is incorporated herein by reference.

ENBRIDGE GAS DISTRIBUTION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2011

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 14, 2012 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) for the year ended December 31, 2011, which are prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

OVERVIEW

The Company is a rate-regulated natural gas distribution utility that has been in operation for more than 160 years. The Company serves approximately 2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario, including the City of Toronto and surrounding areas of Peel, York and Durham regions, as well as the Niagara Peninsula, Ottawa, Brockville, Peterborough, Barrie and many other Ontario communities. In addition, the Company serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates unregulated facilities in Ontario, including two solar projects located in Amherstburg, Ontario, through its 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg) and unregulated natural gas storage facilities.

PERFORMANCE OVERVIEW

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to the common shareholder	**209**	191	218
Earnings excluding the effect of weather[1]	**208**	203	201
Cash flow data			
Cash provided by operating activities	**514**	512	953
Cash used by investing activities	**(464)**	(365)	(384)
Cash used by financing activities	**(54)**	(154)	(661)
Dividends			
Common share dividends declared	**220**	215	188
Dividends declared per common share	**1.56**	1.53	1.34
Preferred share dividends declared	**2**	2	3
Dividends declared per preferred share	**0.60**	0.52	0.84
Total revenues	**2,466**	2,475	2,903
Total assets	**7,315**	7,152	6,998
Total long-term liabilities	**4,054**	3,871	3,547

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

EARNINGS ATTRIBUTABLE TO THE COMMON SHAREHOLDER

Earnings attributable to the common shareholder were $209 million for the year ended December 31, 2011 compared with $191 million for the year ended December 31, 2010. The increase was primarily due to colder weather, lower interest expense, lower income taxes, lower earnings sharing, customer growth and higher distribution charges. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

Earnings attributable to the common shareholder were $191 million for the year ended December 31, 2010 compared with $218 million for the year ended December 31, 2009. The decrease primarily resulted from warmer weather and higher depreciation and amortization expense, partially offset by customer growth, higher distribution charges and lower income taxes. Depreciation and amortization expense was higher due to an increase in the overall asset base, including the implementation of a new customer billing system in late 2009.

EARNINGS EXCLUDING THE EFFECT OF WEATHER

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings attributable to the common shareholder	**209**	191	218
(Colder)/warmer than normal weather	**(1)**	12	(17)
Earnings excluding the effect of weather	**208**	203	201

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

Normal weather is the weather forecast by the Company in its distribution franchise 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 recent weather trend.

Earnings excluding the effect of weather were $208 million for the year ended December 31, 2011 compared with $203 million for the year ended December 31, 2010. The increase was primarily due to lower interest expense, lower income taxes, lower earnings sharing and customer growth. This was partially offset by higher operating and administrative expenses and higher depreciation and amortization expense.

Earnings excluding the effect of weather were $203 million for the year ended December 31, 2010 compared with $201 million for the year ended December 31, 2009. The increase was primarily due to customer growth, higher distribution charges and lower taxes, partially offset by higher depreciation and amortization expense.

REVENUES

Revenues for the year ended December 31, 2011 were $2,466 million compared with $2,475 million for the year ended December 31, 2010. The decrease in revenues was primarily a result of lower natural gas prices and other revenue, partially offset by colder weather, customer growth and higher distribution charges.

Revenues for the year ended December 31, 2010 were $2,475 million compared with $2,903 million for the year ended December 31, 2009. The decrease in revenues was primarily a result of lower natural gas prices and warmer weather compared to the prior year, partially offset by customer growth and higher distribution charges.

FORWARD-LOOKING INFORMATION

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

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

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

NON-GAAP MEASURE

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

STRATEGY

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

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

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

RECENT DEVELOPMENTS

AMHERSTBURG SOLAR PROJECTS

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. Project Amherstburg holds two solar projects, consisting of separate 10 megawatt (MW) and 5-MW facilities, both located in Amherstburg, Ontario. The total consideration transferred for the two projects was approximately $66 million, and was primarily funded by the issuance of common shares. The remaining 0.1% limited partnership interest is owned by the general partner, Project AMBG2 Inc., a wholly-owned subsidiary of Enbridge. First Solar Inc. constructed both facilities under fixed price engineering, procurement and construction agreements, and is providing operating and maintenance services for a period of 10 years to both projects, with an optional 10-year renewal. Construction was completed and commercial operations commenced in August 2011. The combined facilities' power output is being sold to the Ontario Power Authority pursuant to 20-year fixed price power purchase agreements. The investment complies with the *Affiliate Relationships Code for Gas Utilities* issued by the OEB and the Company's Undertakings to the Lieutenant Governor in Council for the Province of Ontario.

CUSTOMER CARE AGREEMENT EXTENSION

In February 2011, the Company's Board of Directors approved a five-year nine month extension to the Company's customer care services contract with a third party service provider for call centre, collections and billing services. This contract extension is effective April 1, 2012 and has been structured to provide enhanced levels of customer service and cost certainty. The total cost of the customer care services during the term of the extension is approximately $360 million. The Company filed an application with the OEB in June 2011 requesting that the OEB establish a procedure to facilitate the completion of a regulatory settlement agreement and subsequent approval of the rate recovery of the costs associated with the extended customer care services contract and other related costs. The OEB approved the Company's recovery of costs associated with the agreement in September 2011. Other elements of the customer care services also form part of the settlement agreement.

COST OF CAPITAL

In December 2009, the OEB issued a report making several changes to the cost of capital for Ontario's regulated utilities. The report's new policy guidelines forecasted a new base level return on equity (ROE) of 9.75% for the Company's 2010 rate year, which was higher than the 8.37% generated by the 1997 ROE formula. In its 2010 rate application, the Company applied to the OEB for approval to use the new ROE formula to determine the annual earnings sharing with customers for 2010 and the remainder of the IR term. The OEB issued a decision in May 2010 that the new ROE is not to be used for such earnings sharing determinations. The Company appealed the OEB's 2010 decision to the Ontario Divisional Court and the appeal was dismissed by the Divisional Court in March 2011. As a result, earnings sharing will continue to be calculated on the basis of the 1997 ROE formula for the balance of the IR term. The Company has applied for the new ROE to determine rates after the conclusion of the IR term, commencing with the 2013 rate year.

UNREGULATED STORAGE SERVICES AND NEXUS PROJECT

The deregulation of new natural gas storage in Ontario, coupled with the growing need for high-deliverability storage services by gas-fired power generators and other users, has created unregulated storage growth opportunities for the Company. As of December 31, 2011, the Company had expanded its storage capacity by 12% (to total capacity of approximately 0.3 billion cubic metres or 12 billion cubic feet (bcf)), compared to pre-deregulation capacity, and sold unregulated storage services into the storage market.

The Nexus Project is a 4.5 bcf expansion of the Company's unregulated natural gas storage facility near Sarnia, Ontario. The project, which has received regulatory approval for construction, is secured by a long-term commercial contract. Construction began in the second quarter of 2011 and was completed in 2011 at an approximate capital cost of $34 million. Additional remediation and close-out activities are expected to be performed in 2012 to bring the total capital cost to approximately $38 million.

APPOINTMENT OF NEW PRESIDENT

Effective September 1, 2011, Mr. Guy Jarvis was appointed as President of the Company. At the same time, Ms. Janet Holder, the Company's previous President, was appointed Executive Vice President, Western Access, Enbridge.

RESULTS OF OPERATIONS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Gas distribution margin	**1,021**	995	1,025
Other revenue	**104**	108	108
Operating and administrative expenses	**(419)**	(393)	(385)
Depreciation and amortization	**(281)**	(270)	(254)
Municipal and other taxes	**(41)**	(44)	(49)
Earnings sharing	**(13)**	(19)	(19)
Affiliate financing income	**63**	63	63
Interest expense	**(172)**	(186)	(190)
Income taxes	**(51)**	(61)	(78)
Earnings	**211**	193	221
Earnings Attributable to the Common Shareholder	**209**	191	218

GAS DISTRIBUTION MARGIN

Gas distribution margin for the year ended December 31, 2011 increased by $26 million compared with the year ended December 31, 2010. The increase was primarily due to colder weather, customer growth and higher distribution charges.

The heating degree days reported in 2011 were 5 heating degree days warmer compared with forecast heating degree days. However, due to the relative effectiveness and monthly distribution of heating degree days in the year, on a weather-normalized basis, net gas distribution margin for the year ended December 31, 2011 would have been lower by $1 million (2010 - higher by $17 million). As experienced in 2010, there was significant variability in the 2011 heating degree day profiles of the geographical regions in which the Company operates. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude. Weather, measured in heating degree days, was 3,597 heating degree days for the year ended December 31, 2011 compared with 3,466 heating degree days for the year ended December 31, 2010.

Gas distribution margin for the year ended December 31, 2010 decreased by $30 million compared with the year ended December 31, 2009. The decrease was primarily due to warmer weather, partially offset by customer growth and higher distribution charges.

The heating degree days reported in 2010 were 80 heating degree days warmer compared with forecast heating degree days, with significant variability in the heating degree day profiles of the geographical regions in which the Company operates, unlike what was experienced in 2009. On a weather-normalized basis, net gas distribution margin in the year ended December 31, 2010 would have been higher by approximately $17 million (2009 - lower by $25 million). Weather, measured in heating degree days, was 3,466 degree days for the year ended December 31, 2010 compared with 3,767 heating degree days for the year ended December 31, 2009.

OTHER REVENUE

Other revenue for the year ended December 31, 2011 decreased by $4 million compared with the year ended December 31, 2010. The decrease was primarily due to higher Shared Savings Mechanism revenue in the prior year which resulted from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers. Contributing to the decrease was lower revenue from the management of fee-for-service energy efficiency initiatives. This was partially offset by revenue from Project Amherstburg and higher unregulated storage revenue.

Other revenue for the year ended December 31, 2010 was consistent with that of the year ended December 31, 2009. Incremental revenues during the year were derived from the management of fee-for-service energy efficiency initiatives and from unregulated storage operations due to additional contracts for storage services; however, these were offset by the inclusion of interest income in fiscal 2009 relating to recovery of a GST overpayment.

OPERATING AND ADMINISTRATIVE

Operating and administrative expenses for the year ended December 31, 2011 increased by $26 million compared with the year ended December 31, 2010. The increase was primarily due to higher employee related costs, higher pipeline integrity and safety costs, and higher customer support related costs.

Operating and administrative expenses for the year ended December 31, 2010 increased by $8 million compared with the year ended December 31, 2009. The increase was primarily due to higher costs relating to the management of fee-for-service energy efficiency initiatives for external parties and higher employee related costs, partially offset by lower customer support related costs due to the implementation of a new customer billing system in late 2009.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization charge for the year ended December 31, 2011 increased by $11 million compared with the year ended December 31, 2010. Depreciation was higher primarily due to an increase in the overall asset base resulting from customer growth projects and improvements to the distribution system.

Depreciation and amortization charge for the year ended December 31, 2010 increased by $16 million compared with the year ended December 31, 2009. Depreciation was higher primarily due to an increase in the overall asset base mainly resulting from the implementation of a new customer billing system in late 2009.

MUNICIPAL AND OTHER TAXES

Municipal and other taxes for the year ended December 31, 2011 decreased by $3 million compared with the year ended December 31, 2010. The decrease was primarily due to the elimination of Ontario's capital tax in 2010.

Municipal and other taxes for the year ended December 31, 2010 decreased by $5 million compared with the year ended December 31, 2009. The decrease was primarily due to the elimination of Ontario's capital tax.

EARNINGS SHARING

Earnings sharing represents the estimated customer portion of regulated earnings in excess of 100 basis points above the ROE threshold currently applicable to the Company, relating to the approved IR formula for the current fiscal year and relating to the OEB's ROE policy guideline in effect prior to December 2009. The earnings sharing mechanism resulted in the return of revenue of $13 million to customers for the year ended December 31, 2011 (2010 - $19 million; 2009 - $19 million), subject to OEB approval in 2012. There was approximately $6 million in lower earnings sharing during 2011 as compared to 2010 even though there was no significant variance in regulated earnings. The lower earnings sharing is primary as a result of a higher rate base threshold in 2011 compared to the prior period.

INTEREST EXPENSE

Interest expense for the year ended December 31, 2011 decreased by $14 million compared with the year ended December 31, 2010. The decrease was primarily due to the Company's redemption of its $150 million 10.80% debentures in April 2011, which were replaced with the issuance of $100 million medium term notes (MTNs) at 4.95% and additional draws on its credit facilities at lower interest rates.

Interest expense for the year ended December 31, 2010 decreased by $4 million compared with the year ended December 31, 2009. The decrease was primarily due to the Company's redemption of its $100 million 11.15% debentures in March 2009 and lower credit facility fees resulting from more favourable market conditions.

INCOME TAXES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings before income taxes	**262**	254	299
Income taxes	**51**	61	78
Effective tax rate (%)	**19.5**	24.0	26.1

The effective tax rate for the year ended December 31, 2011 was lower compared with the year ended December 31, 2010. The decrease was due to temporary differences relating to property, plant and equipment and intangible assets, and an approximate 2.75% reduction in the combined federal and Ontario income tax rates.

The effective tax rate for the year ended December 31, 2010 was lower compared with the year ended December 31, 2009. The decrease was primarily due to a 1.0% reduction in each of the federal and Ontario income tax rates.

RATE REGULATION

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

INCENTIVE REGULATION

In 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.

In 2008, the Company moved to an IR methodology. The objectives of the IR Settlement are as follows:

- reduce regulatory costs;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide more stable rates to customers.

In preparation for the conclusion of the current IR term at the end of 2012, the Company has recently filed a 2013 Cost of Service (COS) application. The Company expects the OEB to address the application in 2012.

2012 RATE ADJUSTMENT APPLICATION

In September 2011, the Company filed an application with the OEB to adjust rates for 2012 pursuant to the approved IR formula. The Company applied for distribution revenue of $1,024 million, and $1,004 million or 98%, was approved for recovery by the OEB, pursuant to a settlement agreement with the intervenors representing customers. The rate adjustment was effective January 1, 2012. A hearing with respect to the remaining $20 million applied for distribution revenue and related issues was held by the OEB in January 2012 with a decision expected by April 2012.

2011 RATE ADJUSTMENT APPLICATION

In September 2010, the Company filed an application with the OEB to adjust rates for 2011 pursuant to the approved IR formula. The total distribution revenue applied for was approved by the OEB, with the rate adjustment being effective January 1, 2011.

2010 RATE ADJUSTMENT APPLICATION

In September 2009, the Company filed an application with the OEB to adjust rates for 2010 pursuant to the approved IR formula and to seek approval for specific changes to the Rate Handbook. Pursuant to the subsequent filing with the OEB of a settlement agreement with ratepayer groups, the Company received approval of a fiscal 2010 final rate order from the OEB in March 2010 approving the implementation of a rate change effective April 1, 2010, which enabled the Company to recover the approved revenues as if rates were effective January 1, 2010.

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 (AcG-19), *Disclosures by Entities Subject to Rate Regulation*, requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 3 to the 2011 Annual Consolidated Financial Statements.

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

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

There are other areas where the determination of the amounts to be recovered in current rates is different from the determination that would be reported by a non-regulated business, and the Company records those items on the same basis as they are recovered in rates. Future removal and site restoration reserves, 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 liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. However, the regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

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

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations and the issuance of replacement debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay dividends.

In 2010, the Company issued $200 million of new 10 year MTNs at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%. In 2011, the Company issued additional $100 million additional MTNs under the same terms as the $200 million 40 year MTN pricing supplement issued in 2010 at an interest rate of 4.95%. In 2011, the Company had total debenture maturities of $150 million (2010 - $150 million).

In July 2011, the Company extended the maturity date of the $700 million committed line of credit for an additional year to August 2012, with an additional one-year term out option.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company's credit facilities at December 31, 2011.

	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	**700**	**545**	**155**
St. Lawrence Gas Company, Inc.	**12**	**10**	**2**
Total credit facilities	**712**	**555**	**157**

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

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

December 31,	**2011**	2010
(millions of Canadian dollars)		
Cash and cash equivalents	**9**	13
Accounts receivable and other	**663**	802
Gas inventories	**380**	400
Bank overdraft	**(7)**	(17)
Short-term borrowings	**(556)**	(332)
Accounts payable and other	**(713)**	(850)
Working capital	**(224)**	16

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, 2011, this ratio was 2.65 (2010 - 2.64). 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.

OPERATING ACTIVITIES

Cash provided by operating activities was $514 million for the year ended December 31, 2011 compared with $512 million in 2010. The increase was due to a decrease in receivables from customers as a result of the impacts of weather, offset by an increase in the net settlement on purchase gas variances owing to customers.

Cash provided by operating activities was $512 million for the year ended December 31, 2010 compared with $953 million in 2009. The decrease was primarily due to insignificant increases in accounts receivable and gas inventories compared to significant decreases in 2009. These impacts were primarily the result of fluctuations in the market price of natural gas.

INVESTING ACTIVITIES

Cash used for investing activities was $464 million for the year ended December 31, 2011 compared with $365 million in 2010. The increase was primarily due to higher comparative capital spending on unregulated natural gas storage projects, customer growth projects, improvements to the distribution system and construction of a technical training facility.

Cash used for investing activities was $365 million for the year ended December 31, 2010 compared with $384 million in 2009. The decrease was primarily due to spending in 2009 for a new customer billing system, which was implemented in late 2009, partially offset by higher comparative spending in 2010 for distribution system improvements.

CAPITAL EXPENDITURES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
System improvements and upgrades	**159**	160	144
System expansion	**140**	107	107
Computers and communication equipment	**38**	32	73
Unregulated storage	**32**	7	12
Solar assets (Project Amherstburg)	**68**	-	-
Other	**106**	59	34
Total capital expenditures	**543**	365	370

The Company's existing distribution network consists of approximately 35,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required in addition to capital improvements.

The Company expects to spend approximately $440 million in 2012 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $415 million.

The 2012 capital projects include the cast iron replacement program, construction of the technical training facility, the Greater Toronto Area (GTA) reinforcement project and power generation projects. The Company expects to finance these expenditures through cash from operating activities and available liquidity.

FINANCING ACTIVITIES

Cash used for financing activities was $54 million for the year ended December 31, 2011 compared with $154 million in 2010. The decrease was primarily due to issuances of short-term borrowings and the issuance of $100 million MTNs, partially offset by the repayment of the portion of long-term debt that became due.

In 2010, cash used for financing activities was $154 million compared with $661 million in 2009. The decrease was primarily due to $400 million of MTN issuances in 2010 and lower net repayments of short-term borrowings compared to the prior year as a result of decreased cash from operating activities, partially offset by a larger debenture maturity and an increase in common share dividends paid compared to the prior year.

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

PREFERRED SHARES

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

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

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

Outstanding Share Data[1]

	Number
Preferred Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common shares	142,345,114

1. *Outstanding share data information is provided as at February 14, 2012.*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2010 and December 31, 2011.

Consolidated Statements of Financial Position Category	**Increase/ (Decrease)**	**Explanation**
(millions of Canadian dollars)		
Accounts receivable and other	(139)	Primarily due to warmer weather in the fourth quarter and lower commodity prices.
Property, plant and equipment, net	312	Primarily due to an increase in the overall asset base resulting from the acquisition of Project Amherstburg assets and expenditures on unregulated natural gas storage projects, customer growth projects, improvements to the distribution system and construction of a technical training facility.
Short-term borrowings	224	Primarily to fund working capital needs.
Accounts payable and other	(137)	Primarily due to refunds of gas price variances to customers.
Current maturities of long-term debt	(150)	Repayment of the current portion of long-term debt.
Long-term debt	107	Primarily due to a $100 million MTN issue.
Other long-term liabilities	69	Primarily due to increased regulatory liabilities from future removal and site restoration reserves and pensions.
Share capital – common shares	66	Issuance of common shares to fund the Project Amherstburg acquisition.

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 borrows or loans natural gas from/to transportation service customers. Specific defined parameters are in place and are monitored carefully to ensure that the volume of natural gas loaned does not exceed certain threshold levels. Customer accounts beyond

these defined threshold levels incur penalties. All loaned volumes are trued up annually. The Company also has strict credit policies in place to mitigate this risk. See CREDIT RISK.
Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2011, $100 million of natural gas was held on behalf of transportation service customers (December 31, 2010 - $102 million). These transactions have no impact on the Company's consolidated earnings or financial position.

CONTINGENCIES AND COMMITMENTS

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

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

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

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

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

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2012 fiscal years, the OEB approved the establishment of deferral accounts. The issue of whether the possible claims and related costs are recoverable from customers has yet to be determined.

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

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

BLOOR STREET INCIDENT

The Company was 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 in April 2003 on Bloor Street West in Toronto. In December 2011, the Company pleaded guilty before the Ontario Court of Justice to one charge under OHSA and one charge under TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by the Company was $875,000.

OTHER LITIGATION

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

CONTRACTUAL OBLIGATIONS

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

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt [1]	2,387	-	400	-	1,987
Loans from affiliate company [1]	375	-	-	-	375
Services contracts [2]	26	18	8	-	-
Customer care service contracts [3]	359	58	115	122	64
Gas transportation and storage contracts	927	628	193	90	16
Pension and OPEB obligations [4]	24	24	-	-	-
Total contractual obligations	4,098	728	716	212	2,442

1. *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*
2. *Consists of fixed overhead payments to contractors and fees relating to services provided for work and asset management initiatives. The majority of the latter expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2011, $133 million (2010 - $124 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*
3. *In 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*
4. *Assumes only required payments will be made into the pension and OPEB plans in 2012. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2011. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

QUARTERLY FINANCIAL INFORMATION

2011	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
(millions of Canadian dollars)					
Revenues[1]	**999**	**473**	**315**	**679**	**2,466**
Earnings attributable to the common shareholder[1]	**108**	**50**	**9**	**42**	**209**
Colder/(warmer) than normal weather	**11**	**2**	**-**	**(12)**	**1**

2010	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars)					
Revenues[1]	1,002	423	297	753	2,475
Earnings attributable to the common shareholder[1]	86	28	8	69	191
(Warmer)/colder than normal weather	(8)	(10)	-	6	(12)

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

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

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

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

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

FOURTH QUARTER 2011 HIGHLIGHTS

Earnings attributable to the common shareholder were $42 million for the three months ended December 31, 2011 compared with $69 million for the same period in 2010. The decrease was primarily due to warmer weather, lower other revenue, higher operating and administrative expenses, and higher depreciation and amortization expense during the period. This was partially offset by lower income taxes and lower interest expense.

Earnings applicable to the common shareholder were $69 million for the three months ended December 31, 2010 compared with $72 million for the same period in 2009. The decrease of $3 million was primarily due to tax differences relating to intangible assets, partially offset by lower interest expense from lower credit facility fees.

RELATED PARTY TRANSACTIONS

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

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, 2011, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2011, dividends received amounted to $63 million (2010 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2011 (2010 - $5 million).

IPL System Inc. advanced the Company $375 million ($200 million at 6.85% and $175 million at 7.50%) repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preferred shares of the Company. For the year ended December 31, 2011, interest paid amounted to $20 million (2010 - $27 million) with an outstanding payable balance of $9 million at December 31, 2011 (2010 - $2 million).

Enbridge (U.S.), an affiliated company under common control, advanced a subsidiary of the Company $8 million (2010 - $6 million) at the LIBOR rate plus 0.55%, payable on demand.

Enbridge, the ultimate parent company, provides 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, 2011 were $34 million (2010 - $32 million) with an outstanding payable balance of $1 million at December 31, 2011 (2010 - $1 million).

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, 2011 were $28 million (2010 - $30 million) with an outstanding receivable of $4 million at December 31, 2011 (2010 - $5 million).

Vector Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $24 million (2010 - $27 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Vector 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, 2011 were $2 million (2010 - $1 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

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, 2011 were $25 million (2010 - $25 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Alliance Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2011 were $18 million (2010 - $17 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Enbridge Commercial Services Inc., an affiliated company under common control, provides information services to the Company. Total charges for the year ended December 31, 2011 were nil (2010 - $2 million) with an outstanding payable of nil at December 31, 2011 (2010 - nil).

Other Transactions
In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

REGULATORY RISK
The Company's operations are regulated and are subject to regulatory risk. The Company retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

The formula currently approved by the OEB for determination of the ROE, which is embedded and escalated within rates over the IR period, is based on the OEB's risk assessment of the Company for the 2007 fiscal year (refer to RECENT DEVELOPMENTS – COST OF CAPITAL).

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

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

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

VOLUME RISKS

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

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

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

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

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

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 80% (2010 - 80%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

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

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

MARKET PRICE RISK

The Company’s earnings, cash flows and other comprehensive income are subject to movements in interest rates, foreign exchange rates and natural gas commodity prices (collectively, market price risk). 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 section summarizes the primary types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk

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

Foreign Exchange Risk

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

Natural Gas Price Risk

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

CREDIT RISK

Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables.

The Company minimizes credit risk to derivative counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant concentration with any single counterparty.

FINANCING RISK

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

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

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments, as they become due. To manage this risk, the Company forecasts the cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of replacement debt, commercial paper and/or credit facility draws. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets.

MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

Based on valuations at December 31, 2011, the Company's financial derivative instruments will give rise to $1 million undiscounted cash outflows in 2012.

FINANCIAL INSTRUMENTS

December 31, 2011	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	9	-	-	-	-	-	9	9
Accounts receivable and other	-	-	614	-	-	49	663	614
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	7	-	-	-	-	-	7	7
Short-term borrowings	-	-	-	556	-	-	556	556
Accounts payable and other	-	-	-	654	1	58	713	655
Long-term debt	-	-	-	2,374	-	-	2,374	2,943
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	13	-	-	-	-	-	13	13
Accounts receivable and other	-	-	722	-	-	80	802	722
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	17	-	-	-	-	-	17	17
Short-term borrowings	-	-	-	332	-	-	332	332
Accounts payable and other	-	-	-	611	1	238	850	612
Long-term debt	-	-	-	2,417	-	-	2,417	2,775
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

1. *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market.*
2. *Investment in affiliate company and loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined.*

Fair Value of Financial Instruments

The fair value of financial instruments reflects the Company's best estimates of fair 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 attributable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date.

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

DERIVATIVE INSTRUMENTS

The total notional principal or quantity outstanding related to the Company's derivative instruments at December 31, 2011 include $111 million of interest rate contracts and 6 million cubic metres of natural gas contracts, both maturing in 2012.

Additional information about the Company's Risk Management and Financial Instruments is included in Notes 14 and 15 of the 2011 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

Distribution Network Operating Risk

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

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

The Company has an extensive program to manage pipeline integrity, which includes the development and use of in-line inspection tools for pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Company also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While the Company considers the level of insurance to be adequate, it may not be sufficient to cover all potential losses.

Environmental, Health and Safety Risk

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

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

Climate Change Legislation

Federal and Provincial carbon regulations remain in development. With the withdrawal of Canada from the Kyoto protocol, sector specific carbon related regulations may develop. It is currently unclear how natural gas distributors will be specifically treated.

Ontario and Quebec, as members of the Western Climate Initiative, are implementing reporting and cap and trade programs respectively to meet their stated GHG reduction targets. GHG reporting in Ontario was implemented in 2011, with subsequent years requiring verification of the data submitted. Quebec has announced a pilot cap and trade program prior to proposed regulatory compliance requirements. The Company will continue to monitor provincial developments and respond accordingly.

The Company is on track to deploy a carbon data management system to ensure compliance with 2012 reporting requirements. The Company continues to publicly report our GHG emissions and will continue to develop internal procedures to identify operationally related GHG reductions.

Reputation Risk

The Company’s reputation is one of its most valuable assets. Reputation risk is the risk of negative impacts on the Company’s business, operations or financial condition resulting from changes in the Company’s reputation with stakeholders and other entities. These potential impacts may include loss of business, legal action or increased regulatory oversight.

Reputation risk often arises as a consequence of some other risk event, such as operating, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations;
- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company’s Corporate Social Responsibility Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative and the Company’s commitment to Green Energy).

CRITICAL ACCOUNTING ESTIMATES

REVENUE RECOGNITION

The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced.

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2011 of $4,770 million (2010 - $4,458 million), or 65% of total assets (2010 - 62%), is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2011. The external consulting firm also provides a framework for the Company's calculation of the estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

REGULATORY ASSETS AND LIABILITIES

The Regulators exercise statutory authority over matters such as construction, rates and rate-making, and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under 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, 2011, the Company's regulatory assets totaled $269 million (2010 - $296 million) and regulatory liabilities totaled $1,076 million (2010 - $1,171 million). To the extent that the Regulators' actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POST-EMPLOYMENT BENEFITS

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees and post-employment benefits other than pensions (OPEB) to eligible retirees.

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

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

The difference between the actual and expected return on plan assets was a shortfall of $38 million for the year ended December 31, 2011 (2010 - $29 million) as disclosed in Note 18 to the 2011 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension and OPEB plans, funding in 2012 will be $24 million.

The following sensitivity analysis identifies the impact on the December 31, 2011 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	60	6	7	-
Decrease in expected return on assets	n/a	4	n/a	-
Decrease in rate of salary increase	(8)	(2)	-	-

CONTINGENT LIABILITIES
Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 21 of the 2011 Annual Consolidated Financial Statements.

REGULATORY GOVERNANCE

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

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

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

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

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates.

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

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

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

CHANGES IN ACCOUNTING POLICIES

BUSINESS COMBINATIONS
Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations,* which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings, cash flows or financial position for the year ended December 31, 2011.

CONSOLIDATED FINANCIAL STATEMENTS AND NONCONTROLLING INTERESTS
Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and noncontrolling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings, cash flows, or financial position for the current or prior periods presented.

FUTURE ACCOUNTING POLICY CHANGES
United States Generally Accepted Accounting Principles (U.S. GAAP)
First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of The CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has presented its consolidated financial statements in accordance with Part V of the CICA Handbook in the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business and performance measurement. A rate regulated accounting standard model was not finalized by the International Accounting Standards Board in advance of 2012. As a wholly-owned subsidiary of a United States Securities and Exchange Commission (SEC) registrant, the Company has received permission from the Canadian securities regulators to prepare its consolidated financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual consolidated financial statements beginning on January 1, 2012.

In preparation for the U.S. GAAP conversion, Enbridge has formed a U.S. GAAP project team and developed a transition plan and governance structure to monitor the progress of the transition. The Company has engaged a public accounting firm to assist with the project and to provide technical accounting advice on the interpretation and application of U.S. GAAP to its primary consolidated financial statements. Management reports regularly to the Audit, Finance & Risk Committee of the Board of Directors on the advancement of the conversion to U.S. GAAP.

Accounting and Reporting

The Company is in the process of integrating known U.S. GAAP differences into its primary consolidated financial statements. The most significant differences impact the following areas:

- Push-down accounting as a result of a business combination;
- Pensions and other post-employment benefits; and
- Presentation of deferred financing costs.

The Company will commence reporting using U.S. GAAP as its primary basis of accounting in the first quarter of 2012. To facilitate users' understanding of the transition, subsequent to filing its Canadian GAAP consolidated financial statements for the year ended December 31, 2011 and before filing its first interim report under U.S. GAAP, the Company will be filing, for information purposes, its 2011 comparative consolidated financial statements restated under U.S. GAAP along with comparative periods and related note disclosures.

Training

The Company has provided U.S. GAAP training to internal personnel impacted by the conversion. U.S. GAAP training will continue into and beyond 2012 as a regular business activity.

Information Systems and Business Processes

The Company has completed testing system changes necessary to support the conversion to U.S GAAP and to sustain U.S. GAAP reporting in 2012 and beyond. Implementation of these changes will take place in the first quarter of 2012. Impacts to internal controls over financial reporting and disclosures have been evaluated and no significant impacts were noted.

Business Activities

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

The detailed project plan and the expected timing of key activities identified above may change prior to the U.S. GAAP conversion date due to economic conditions or other factors.

ENBRIDGE GAS DISTRIBUTION INC.
HIGHLIGHTS

Year ended December 31,	**2011**	2010
Financial *(millions of Canadian dollars)*		
Gas commodity and distribution revenue	**2,010**	1,977
Transportation of gas for customers	**352**	390
Other revenue	**104**	108
Total revenue	**2,466**	2,475
Gas commodity and distribution costs	**(1,341)**	(1,372)
	1,125	1,103
Earnings	**211**	193
Earnings attributable to the common shareholder	**209**	191
Return on equity[1] (%)	**11.3**	10.3
Operating		
Volumetric statistics *(millions of cubic metres)*		
Gas commodity sales	**6,257**	5,550
Transportation of gas for customers	**5,370**	5,584
Unbundled volumes[2]	**434**	460
Total volume	**12,061**	11,594
Number of active customers[3] *(thousands)*	**1,997**	1,963
Heating degree days[4]		
Actual	**3,597**	3,466
Forecast based on normal weather	**3,602**	3,546

1. *Return on equity data relates to the consolidated entity.*
2. *Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.*
3. *Number of active customers is the number of natural gas consuming customers at the end of the year.*
4. *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the Greater Toronto Area.*

2011 DISTRIBUTED ENERGY, GREEN ENERGY INITIATIVES AND FUEL CELLS ACTIVITIES

1. The purpose of this evidence is to set out the costs associated with activities undertaken within Enbridge Gas Distribution Inc.("Enbridge" or the "Company") related to distributed energy, green energy initiatives and fuel cells, and address the appropriateness of any eliminations from overall expenses related to those activities as agreed at EB-2011-0008, Exhibit N1, Tab 1, Schedule 1, page 12.

Background

The Role of Business Development at Enbridge Gas Distribution

2. Business Development activities have long formed an integral role at Enbridge. Over the years, the Company has developed and managed numerous initiatives designed to cost effectively retain and add gas load to the Company's distribution system.

3. This includes an active pursuit of new technologies and applications with the objective of helping to sustain the competitive position of natural gas in the energy marketplace, lowering overall costs to customers.

4. As part of these efforts, Enbridge is focused on identifying and developing non-traditional and emerging growth opportunities for the Company. It is expected that such initiatives will eventually be integrated with other areas of the regulated utility once the opportunities have been established or more fully developed.

5. In concert with these objectives, staff in the Business Development group work with staff in Market Development and Sales to identify projects that have a

strategic market fit and have a high degree of certainty around potential market penetration and future benefits to the Company and customers.

6. In recent years, the Company's activities have taken account of changes in the Ontario energy marketplace, and have included some focus on activities to support electricity generation and "Green Energy" initiatives. These activities are detailed below.

Summary of Activities

Distributed Energy

7. Distributed Energy is typically modular electric generation installed at or near the point of energy consumption. Gas-fired or fuelled technologies are typically reciprocating engines, gas turbines, micro-turbines, or fuel cell systems.

8. The Company has a sub-group, "Strategic Accounts" within Customer Care that supports power generation customers during the project development and operations stages. This support includes facilitating customers with their contracting needs for regulated distribution services and acting as a point of coordination between the customer and other Enbridge departments. Current customers include Portlands Energy Centre, Goreway, Thorold Cogen and York Energy Centre. The group also follows the developments in the power generation industry to recommend enhancements to Enbridge's regulated services to better serve existing and potential customers. Utility Capital and O&M for specific projects are approved through individual Leave-to-Construct applications to the Ontario Energy Board (the "Board").

9. The Company also supports smaller Distributed Energy customers of roughly 20 MW or below in electrical capacity through its standard attachment and support functions.

10. Activities to support large power generation are core gas distribution utility activities. The costs associated with these activities are embedded in the Customer Care Internal O&M costs outlined in EB-2011-0354 at Exhibit D1, Tab 17, Schedule 1, paragraphs 20 and 21, and Table 1.

11. Activities to support smaller Distributed Energy customers are embedded in various cost centres across the Company as a normal part of core gas distribution utility business (e.g.,Customer Connections, Sales).

Hybrid Fuel Cell Plant

12. The Company owns and operates a hybrid fuel cell plant, located on the property of the Company's head office at 500 Consumers Rd. The plant was established as a pilot project in 2008.

13. The hybrid fuel cell plant provides an alternative method of reducing natural gas pipeline pressure while producing environmentally friendly byproduct electricity in the process. The hybrid fuel cell plant generates ultra-clean electricity by combining two low-carbon technologies, a fuel cell and a turbine that recovers waste energy from the gas as the pressure is reduced during the pressure reduction process.

14. The purpose of the pilot project was a first-of-a-kind demonstration to determine the applicability of applying this technology within Enbridge's franchise area. The intent of the demonstration was to determine the reliability of this alternative

technology and evaluate the ability to integrate this technology on a wider basis across the distribution system. The ratepayer could benefit by employing this technology at pressure reduction stations throughout the network from environmentally friendly electricity revenues generated by electricity production, however, a clean energy program with market premium prices that would support this hybrid technology does not currently exist.

15. Until such time as the Ontario Power Authority establishes an economically feasible feed-in tariff, the Company has no plans for further development.

16. In the absence of a viable feed-in tariff in 2011, the Company used the plant to offset the electrical energy requirements of VPC with the remaining power sold into the grid at the Hourly Ontario Energy Price. The costs to operate and maintain the plant was $114,159 in 2011 and are included in 2011 Operations O&M costs laid out in Exhibit D1, Tab 15, Schedule 1, Table 3. In addition, $78,665 was incurred in 2011 for miscellaneous administrative costs and is included in the 2011 Business Development & Customer Strategy O&M costs at Exhibit D1, Tab 17, Schedule 1, Table 4.

Green Energy Initiatives

17. As part of the Business Development activities noted earlier, the Company has explored emerging trends in the broadly defined field of Green Energy with the goal of understanding the potential long-term implications on the Company's core business and bringing value to utility customers.

18. Through this exploration in 2011, the Company identified an opportunity to establish a Renewable Natural Gas ("RNG") program to enable the development of a viable RNG industry in Ontario. On September 30, 2011, the Company

submitted an application to the Board through EB-2011-0242, for an Order or Orders approving or fixing rates for the sale of gas that include the cost consequences of the purchase of renewable natural gas by Enbridge. For this purpose, RNG means biomethane, which is produced by upgrading biogas produced in anaerobic digesters, and landfill gas produced in landfill facilities.

19. It is the Company's position that the benefits of a RNG program represent significant opportunities, including the opportunity to offer utility customers a more environmentally sustainable gas supply, the opportunity to facilitate a market for producers of biomethane in Ontario, and the opportunity to maximize the efficient use of biogas resources.

20. The Company was involved in two Green Energy projects in 2011, the costs of which will be eliminated from utility costs, as they were not specifically related to the regulated utility business. These activities were: the assessment of a Biomethane development opportunity in Quebec and the exploration of a District Energy development project in Ottawa. The cost for these activities amounts to $106,000 and is presented in Table 1 below. This amount will be eliminated as a non-utility adjustment in the Company's 2011 ESM application.

Table 1
2011 O&M Cost Eliminations for Green Energy

O&M Costs (000's)	District Energy	Biogas Services	Total
Fully Allocated Labour	$ 70.5	$ 27.7	$ 98.2
Program Costs	$ -	$ -	$ -
Expenses	$ 3.8	$ 3.9	$ 7.7
Total Costs	$ 74.3	$ 31.6	$ 106.0

Witness: T. Maclean

21. If the Board approves the Company's RNG application, capital and O&M costs related to the RNG assets and facilities will be recovered from the RNG producer(s). Details related to the proposed regulatory treatment of RNG related costs can be found at EB-2011-0242, Exhibit B, Tab 1, pages 23 and 24.

STORAGE COST ALLOCATION STUDY

PREPARED FOR

Enbridge Gas Distribution Inc.

1 MAY 2012

BLACK & VEATCH
Building a world of difference.

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INTRODUCTION AND SUMMARY

In the Natural Gas Electricity Interface Review ("NGEIR") Decision in EB-2005-0551[1], the Ontario Energy Board (the "Board") determined that the market for the ex-franchise storage services of Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") and Union Gas Limited ("Union") was a competitive market and that Enbridge and Union would no longer be subject to rate regulation for those services. The Board stated that it would cease regulating the prices charged for the following storage services:

- All storage services offered by Union and Enbridge to customers outside their franchise areas;
- New storage services offered by Union and Enbridge to their in-franchise customers; and
- All storage services offered by other storage operators, including storage operators affiliated with Union and Enbridge.[2]

This decision permitted Enbridge to develop new storage services within the competitive market under rates and revenues that would not be regulated by the Board. The Board stated that Enbridge could develop new storage capacity to serve both its in-franchise and ex-franchise customers, however, the Board would not regulate the prices for any of the new storage services developed and offered by Enbridge.

A key element of the Board's decision was that it did not require Enbridge to functionally separate its regulated and unregulated storage operations. At page 73 of its Decision in EB-2005-0551, it was stated that:

> "The Board finds that functional separation is not necessary. The evidence before the Board is that it would be costly and difficult to establish a functional separation of utility and non-utility storage, and there was no evidence to suggest that there would be significant benefits from such a separation. To the extent there may be concerns regarding the integrated operations, these will be addressed through the reporting requirements set out in section 5.4."

Of particular note was that the Board also recognized that all of Enbridge's then existing storage investment was required to serve its in-franchise customers. Therefore, unlike the more complicated situation that existed at that time for Union, it was not necessary for Enbridge to undertake a study of the storage assets that it owned at the time of the NGEIR Decision to determine the portion of its integrated storage operations that was to be allocated to the unregulated storage business.

In response to the Board's Decision, Enbridge established a separate set of books, and implemented a specific accounting and cost allocation process to identify and separate costs between regulated and unregulated storage operations. Enbridge's separate books and cost allocation and accounting

[1] EB-2005-0551 Decision With Reasons issued on November 7, 2006

[2] EB-2005-0551 Decision With Reasons, Page 3.

process accommodate all of the cost elements which support its integrated storage operation, including capital expenditures, Operating & Maintenance ("O&M") expenses, overhead expenses, fuel expenses, and the cost of lost and unaccounted for volumes.

In view of the relative complexities of the process, its level of detail, and its impact upon rate levels, the allocation of costs between Enbridge regulated and unregulated storage operations has been an issue in its recent regulatory proceedings before the Board. In accordance with the provisions of the Settlement Agreement in its 2009 Earnings Sharing Mechanism ("ESM") proceeding (EB-2010-0042), Enbridge agreed to submit as part of its 2010 ESM filing, "an analysis of the appropriate allocation of the costs of regulated and unregulated storage operations."[3] In EB-2011-0008, Enbridge submitted a narrative explanation of the allocation of costs for its regulated and unregulated storage activities.[4] Parties in that proceeding had the opportunity to review Enbridge's submission and to file interrogatories to better understand the nature of its cost allocation process and methods.

One of the provisions of Enbridge's ESM Settlement Agreement in its 2010 ESM proceeding was to address the allocation of costs between its regulated and unregulated storage operations. Specifically, part s, item 3 of the Agreement stated that:

> "For the purpose of reaching an overall settlement, no party opposes Enbridge's allocation of costs between regulated and unregulated storage activities for the purpose of determining the 2010 ESMDA amount. There is no agreement as to whether Enbridge's continued use of its current approach to allocating costs between regulated and unregulated storage is appropriate for future years. Enbridge agrees that, as part of the evidence in support of its 2013 application, it will file a study, prepared by an external expert, evaluating the appropriateness of the allocation of costs between Enbridge's regulated and unregulated storage activities. It is expected that the expert will provide a professional assessment of the methodologies used and recommendations for alternate approaches if, in their opinion, improvements can be made."[5]

Based on Enbridge's review of the proposals submitted in response to its Request for Proposal ("RFP"), Enbridge retained Black & Veatch Corporation ("Black & Veatch") to conduct the required study.

The purpose of this report is to present the results of Black & Veatch's review and evaluation of Enbridge's cost allocation process for its regulated and unregulated storage operations.

SCOPE OF THE REVIEW

Black & Veatch understands that Enbridge required a review of the cost allocation process and methods for its unregulated and regulated underground storage operations.

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[3] EB-2010-0042 Decision and Procedural Order, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, Page 9 of 14, dated July 10, 2010

[4] EB 2011-0008, Exhibit B, Tab 1, Schedule 6 and Appendices, filed on April 20, 2011

[5] EB-2011-0008, Decision and Order, Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, Page 15 of 16, dated July 22, 2011.

Based on this requirement, Black & Veatch structured its review to include the following work tasks:

1. Review and evaluate Enbridge's current cost allocation methodology (and supporting accounting process) for its regulated and unregulated underground storage operations and make recommendations on any changes to the underlying assumptions and/or methodologies.
2. Prepare a written report which sets forth in detail the findings and recommendations of the review with respect to all material issues and methodologies, and which is structured in an appropriate format for submission to the Board and Enbridge's external stakeholders.

Finally, Black & Veatch's particular focus was on the level of storage-related costs that Enbridge incurred, and that were allocated to its two storage businesses, during 2011. This focus was taken because Enbridge's 2011 costs will be the subject of its 2011 ESM filing before the Board and because the allocation of costs presented by Enbridge in past ESM proceedings have already been accepted by the Board for ratemaking purposes. At the same time, however, Black & Veatch did review Enbridge's cost allocation methods and accounting results from prior years for continuity purposes and to better understand to what extent Enbridge's cost allocation treatment has evolved over time.

GUIDING CONSIDERATIONS AND AREAS OF CONCENTRATION

In conducting our review of Enbridge's cost allocation process for its unregulated and regulated storage operations, we were guided by the following considerations:

1. The fundamental and underlying philosophy applicable to every utility cost of service study pertains to the concept of cost causation for purposes of allocating costs to customer groups or service types.
2. Cost causation (or cost causality) addresses the question – *Which customer or groups of customers cause the utility to incur particular types of costs?* To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.
3. *A Key Consideration* – the ability to establish operating relationships between customer service requirements and the costs incurred by the utility in meeting those requirements (e.g., satisfying a customer's peak demand requirements through the incurrence of capacity-related costs to provide the required level of gas delivery service).
4. The three broad steps most often followed to perform utility cost of service studies: (1) cost functionalization; (2) cost classification; and (3) cost allocation will be utilized for this review as a framework for evaluating the various steps involved in Enbridge's current cost allocation process.
5. A utility's cost allocations should stand on their own objective merits (i.e., costs should be assigned to the classes or categories of service based on the design and operational considerations of the utility's system rather than on achieving results that support a desired outcome for the allocation of revenues to classes and/or rate design).
6. Consistency of structure, methodology, and computational details between Enbridge's cost allocation process used for separating its storage-related assets and expenses and the cost

allocation study it utilizes to evaluate the costs of serving its in-franchise customers and service offerings.

7. The Board's findings in the NGEIR Decision (EB-2005-0551).

8. The storage cost allocation methodology used by Union, and any decision made by the Board with respect to that methodology in the EB-2011-0038 proceeding.

We saw our primary roles and responsibilities in this project as follows:

- To understand the system planning, operation, and utilization of Enbridge's underground storage facilities to confirm that cost causation is properly reflected in its cost allocation and accounting processes;
- To understand the differences between the cost accounting for Enbridge's unregulated and regulated storage operations;
- To understand the cost transactions that comprise Enbridge's unregulated and regulated storage operations, including the allocation of costs of its current integrated storage system and its incremental storage facilities; and
- To provide sufficient commentary on our recommendations and supporting information pertaining to alternative cost allocation process and the related treatment of costs so that Enbridge can adequately evaluate our findings and decide whether or not to propose changes in its subsequent rate and regulatory filings with the Board.

These above-described elements defined the focus areas in which Black & Veatch concentrated its review and evaluation in this project. In our review of Enbridge's cost allocation process for its storage lines of business, Black & Veatch conducted its work in a manner so that it could determine:

- If Enbridge's cost allocation methodology for the allocation of costs between its regulated and unregulated storage operations had a conceptual basis that was grounded in sound and acceptable utility costing principles and the operational realities of its gas utility system.

- If there were certain regulatory precedents established by the Board that Enbridge recognized and incorporated into its cost allocation method.

- If Enbridge's cost allocation and accounting methods provided analytical and computational transparency (i.e., did it create a sufficient and verifiable audit trail - identification of input data sources, traceable information flows, identification of each computational step).

OVERALL ASSESSMENT

Based on the results of our review, Black & Veatch's overall assessment consists of the following observations:

1. The conceptual underpinnings and resulting methodologies upon which Enbridge's cost allocation process is based are generally well-conceived and reasonable in their treatment of storage-related plant and expenses. However, there are a few components of Enbridge's current cost allocation methods that Black & Veatch believes should be changed to better recognize the underlying cost causative factors of Enbridge's storage operations.

2. The manner in which Enbridge has presented its separation of costs between its regulated and unregulated storage operations in its past ESM Filings before the Board does not in all cases provide a sufficient level of detail and explanation to allow an outside party to understand, trace, and verify the underlying assumptions of the cost allocation methodology, computational processes, and to independently confirm the results.

RECOMMENDATIONS

Enbridge has considered Black & Veatch's discussions related to the first overall assessment item above and has proposed to revise certain of its current cost allocation methods for the following cost elements:

- **New General Storage Plant**
    1. Enbridge proposes to adopt the cost allocation treatment for new general plant depicted in Schedule 5 and to apply this method to the cost of its Sombra warehouse facility once it is completed and placed into service.

- **Storage Operations**
    1. Enbridge proposes to change its cost allocation factor for fixed storage costs to reflect a proper weighting of the cost drivers of annual capacity and deliverability, and has made minor modifications to the portion of costs it classifies as variable in nature.

    2. Enbridge proposes to eliminate from its current cost allocation process the use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center (see page 2 of Schedule 6).

As a result of the second overall assessment item above, Black & Veatch recommends the following enhancements to Enbridge's computational process and evidentiary presentation:

1. Establish more robust documentation that readily allows the reader to clearly trace how Enbridge's regulated and unregulated storage costs are developed, which should include providing clear references for the cost allocation methods used in the calculation of the costs of Enbridge's unregulated storage operations. Black & Veatch believes that certain of the Schedules presented in this report should be incorporated into Enbridge's future evidentiary presentations before the Board on this subject.

2. Provide additional details to be able to trace Enbridge's elimination from its Utility Income of each particular expense item (e.g., gas costs, O&M expenses, property taxes, and depreciation expense) associated with Enbridge's unregulated storage operation, and the computational details to derive each eliminated amount.

3. The manner in which Enbridge splits the cost of new storage assets that replace existing storage assets with a capacity enhancement component between its regulated and unregulated storage operations (e.g., Enbridge's "Pool Metering Upgrades" project) should be detailed so that the basis for the determination of the cost split can be readily understood by an outside party.

BACKGROUND PERSPECTIVES

As a backdrop and to provide sufficient context to our subsequent detailed review of Enbridge's costing method for its storage lines of business, Black & Veatch initiated its work effort with a review of the operational characteristics and service offerings of Enbridge's integrated storage facilities. Specifically, our review addressed the following activities:

- The physical attributes and operations of Enbridge's Tecumseh storage facilities; and
- The nature and level of storage services available to Enbridge's ex-franchise customers.

In addition, we reviewed the relevant regulatory, ratemaking, and accounting aspects of Enbridge's regulated and unregulated storage operations to better understand the evolution of the issues, regulatory decisions, and implementation processes required to allocate costs to these activities and to account for them in Enbridge's financial statements and ratemaking filings before the Board.

OPERATIONAL

Enbridge's Tecumseh underground storage facilities are located in Southwestern Ontario, near the Dawn Hub, and have been in operation since the 1960s. Enbridge's storage operations consist of 11 storage pools with a total working capacity[6] of approximately 110 Bcf, with a peak deliverability of about 2.5 Bcf per day. In addition, Enbridge owns and operates the Crowland storage facility, which is a small gas storage field with a capacity of 0.4 Bcf located in the Niagara Region that is directly connected to Enbridge's gas distribution system. Included in the 110 Bcf capacity level, Enbridge also operates a 6.7 Bcf storage operation on behalf of, and for use by, Union (the Dow Moore and Black Creek storage pools). Enbridge's Tecumseh gas storage system is depicted in Figure 1. In addition, a summary listing of the operational characteristics of Enbridge's gas storage facilities is presented in Schedule 1.

Enbridge's storage facilities are directly connected to four (4) pipeline systems: the Vector Pipeline, Niagara Gas Transmission-Link Pipeline, TransCanada PipeLines Limited ("TCPL"), and Union. These pipeline interconnections enable Enbridge to provide gas storage services to markets in Eastern Canada, the Midwest U.S., and the Northeast U.S. Figure 2 shows the pipeline interconnections with Enbridge's Tecumseh storage operations. To reach Enbridge's gas utility franchise area in Central and Eastern Ontario, gas stored in the Tecumseh facilities flows over Union's Dawn-Trafalgar gas transmission system, and then through the TCPL system.

Regarding Enbridge's storage operations, its various storage pools are operated as an integrated system with each pool affecting the operation of the other pools throughout the injection and withdrawal periods.

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[6] Also referred to as storage space

Figure 1
Enbridge's Gas Storage Facilities

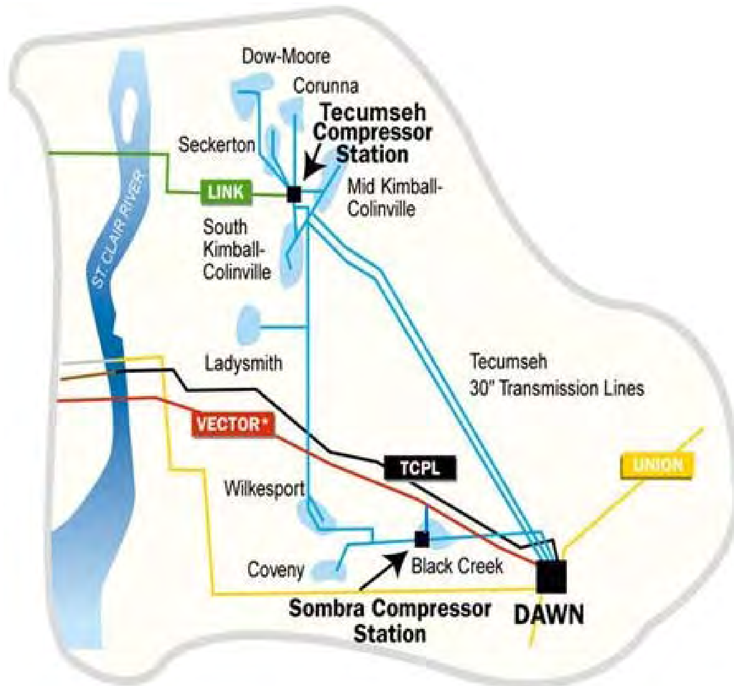
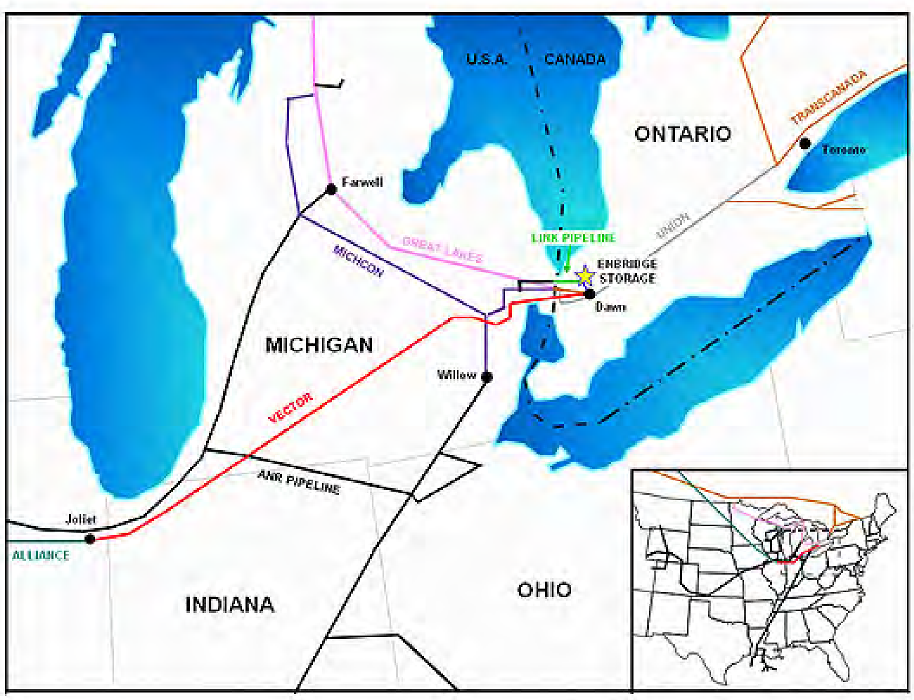


Figure 2
Gas Pipelines Interconnected with Enbridge's Gas Storage Facilities



STORAGE SERVICE CHARACTERISTICS

At the time of the NGEIR Decision, Enbridge required all of its owned storage capacity, in addition to approximately 20 Bcf of storage under multi-year contracts with Union, to serve its in-franchise customers (i.e., regulated utility customers) on a bundled basis. This situation continues to be the case today. In addition, Enbridge has certain larger customers who have chosen to opt out of bundled service by contracting with Enbridge for delivery and storage services on an unbundled basis. Due to the growth of these services over the years, Enbridge now requires approximately 21 Bcf of storage capacity from third-parties to meet its total in-franchise storage requirements.

Enbridge's in-franchise customers, and certain ex-franchise customers, are offered unbundled storage services under its Rates 315, 316, and 325, which are described below.

- Rate 315 – Gas Storage Service (for customers taking service under Rate 125 – Extra Large Firm Distribution Service and Rate 300 – Firm or Interruptible Distribution Service)
- Rate 316 – Gas Storage Service at Dawn (for customers taking service under Rates 125 and 300)
- Rate 325 – Transmission, Compression, and Pool Storage Service (with Union)

Enbridge also offers short-term storage services or Transactional Services ("TS") to third-party customers through the temporarily unused regulated utility storage assets that are considered surplus to its current in-franchise needs. These services have been offered in the marketplace by Enbridge since 1997. TS customers (who are typically more active in the gas market) have the ability to utilize Enbridge's storage services to create supply optimization opportunities premised upon the prevailing natural gas prices. Typical services consist of "park and loan" transactions that are of a short-term nature. "Parks" are services where a third-party injects gas into Enbridge's storage facilities through a TS arrangement for withdrawal at a later time, and "loans" are where the third-party first receives gas out of Enbridge's storage for redelivery to Enbridge at a future time.

To utilize Enbridge's storage resources in this manner, we understand that it is not uncommon for some of Enbridge's short-term storage service customers to cycle their storage inventory 2-3 times in one year (which results in storage transactional volumes equal to 4-6 times the physical storage space).[7] With such high cycling rates (i.e., high inventory turnover ratios), it is not unusual for Enbridge to experience volumetric activity levels for these customers that are much higher than the level of the underlying contracted storage space. In contrast, Enbridge' customers who contract for long-term storage services sometimes cycle their storage space less than once in a particular year (see Schedule 1 for Enbridge's storage turnover rates).

Based on the operational particulars of Enbridge's TS activities, the overall net impact of such transactions can act to offset the traditional seasonal operations of Enbridge's regulated storage activities. As a result, TS activities can serve to reduce the volume of gas that is physically injected into and withdrawn from storage which can generally increase the efficiency of Enbridge's

[7] A customer that contracts for 10 PJ of storage space would be expected to have about 20 PJ of activity to complete one full storage cycle (10 PJ of injections to fill the contracted storage space and 10 PJ of withdrawals to empty the space).

integrated storage operations. At the same time, Enbridge generates incremental revenue from these transactions which is shared between its utility customers and Enbridge's shareholders under a Board approved sharing arrangement.

Enbridge has also been offering competitive storage services at market-based prices since 2008 to gas utilities, wholesale market participants, and power generation customers. These customers comprise Enbridge's unregulated storage market. To accommodate the needs of these customers, Enbridge has been investing since that time in its existing storage operation at Tecumseh to add incremental storage capacity and deliverability beyond the level that existed at the time of the NGEIR Decision. Currently, Enbridge has 12.2 Bcf of unregulated storage capacity. Enbridge also has plans to expand its existing storage facilities based on market demand to take advantage of other market opportunities as they arise such as U.S. Shale gas and gas-fired power generation needs. The level of Enbridge's incremental capital investments in storage for its unregulated operations and the accounting treatment of these investments will be discussed in detail later in this report.

The characteristics of the unregulated storage services offered by Enbridge include:

- Services are offered on a firm and interruptible basis and range from high deliverability (10 or 20 day service)to seasonal storage;
- Customers pay a monthly demand charge, as well as variable charges including the gas commodity and fuel;
- Contract terms that range from 1 to 20 years;
- Customers have the option to cycle gas volumes within their contractual parameters and pay variable charges on the cycled volumes; and
- Overrun services are available on a request basis for an additional fee and must be authorized by Enbridge in advance.

Schedule 1 also provides the annual level of activity for Enbridge's unregulated storage services from 2008 through 2011.

ACCOUNTING FOR STORAGE

To implement a separation model for Enbridge's regulated and unregulated storage operations, as required by the NGEIR Decision, there were three options available to Enbridge: (1) a functional separation; (2) an accounting separation; or (3) an asset divestiture. As pointed out earlier, the Board found that functional separation of the storage assets of Enbridge and Union was not necessary, nor was an asset divestiture a desired alternative in light of their integrated storage operations. Therefore, implementation of an accounting separation process was the only viable alternative for Enbridge to consider.

While the adoption of that approach created the need for the establishment of cost allocation methods to be applied to Enbridge's storage assets, direct expenses, and other indirect costs, the same type of comprehensive process required by Union at that time was not required by Enbridge because: (1) Enbridge required all of its storage assets to satisfy the storage service needs of its in-franchise customers; and (2) Enbridge was not providing unregulated storage services to the natural gas marketplace. A one-time asset separation, therefore, was not required by Enbridge to implement the Boards' findings in the NGEIR Decision. In addition, Enbridge's cost allocation study[8] that it had conducted on or around the time of the NGEIR Decision did not have to be directly relied upon (as was required in Union's case) because there were no storage-related costs that had to be assigned to Enbridge's unregulated storage operations - since the operation did not exist in late 2006.

Enbridge was required, however, on a going forward basis to structure an operational process to identify storage-related investments that were required to support its unregulated storage operations, an accounting process to maintain separate plant records, and an allocation process to assign storage-related expenses to its regulated and unregulated storage operations. The various processes established by Enbridge that have evolved over time have, in our opinion, been greatly influenced by the fact that Enbridge did not have to initially separate by the end of 2007 any of its storage-related assets between regulated and unregulated storage operations.

It is apparent to Black & Veatch that Enbridge's unregulated storage operations has been created in recent years to function as an integral part of an integrated storage operation that served the entirety of its regulated storage requirements on a standalone basis at the time of the NGEIR Decision. On that basis, Enbridge has chosen to utilize an incremental costing approach as a foundation for its identification and assignment of new storage assets to either the regulated or unregulated storage operations. The appropriateness of utilizing this type of a costing approach (in light of Enbridge's specific business situation) compared to a fully allocated costing method that recognizes the common plant characteristics of an integrated utility operation in the derivation of cost allocation methods will be discussed in more detail later in this report.

[8] Used as a guide to evaluate and determine Enbridge's regulated utility revenues and rates for its in-franchise customers.

COST ALLOCATION FOR ENBRIDGE'S STORAGE OPERATIONS

The purpose of this section is to detail the findings and recommendations of Black & Veatch's review and evaluation of Enbridge's cost allocation methods for its regulated and unregulated storage operations. With a basic operational foundation established, a review of Enbridge's cost allocation process structure and framework was conducted. The following areas were reviewed in detail:

- Phases or steps included in the cost allocation process.
- Organizational layout of and interrelationship between filed information and schedules which present Enbridge's cost allocation results.
- Flow of data and sequencing of steps within the cost allocation process.
- Degree to which the cost allocation process is presented on a "self-contained" basis (i.e., analyses and supporting data are an integral part of Enbridge's evidentiary presentation).
- Basis for the total storage cost of service reflected in the cost allocation results.
- The interrelationship and methodological consistency between Enbridge's cost allocation process for its storage operations and its 2007 Board-approved cost allocation study to derive the cost of service for its in-franchise (rate regulated) customers.

Black & Veatch evaluated each element of Enbridge's cost allocation process to determine if its methods and underlying computations were: (1) reflective of how the costs were incurred; (2) fair and equitable; (3) transparent and replicable by an outside party; and (4) consistently applied to each of Enbridge's investment and expense components.

PURPOSE

Enbridge's cost allocation process for its storage operations is used for the following purposes:

1. To separate the costs of Enbridge's unregulated storage operations from its regulated utility operations to properly account for the unregulated operations and to identify regulated storage costs for the purpose of setting Enbridge's regulated utility rates.
2. To identify and compile the results of Enbridge's unregulated storage operations to determine standalone utility financial results for earnings sharing purposes.

The results of Enbridge's cost allocation process for its storage operations are presented each year in its ESM proceeding (e.g., EB-2011-0008), and it is expected that the results will also be submitted in its 2013 rates application, where Enbridge will re-compute the underlying costs of its in-franchise customers to rebase its regulated delivery rates under incentive regulation.

STRUCTURE

Schedule 2 presents a high-level view of the overall functional process Enbridge follows to separate its regulated and unregulated storage costs. Enbridge's overall cost allocation process addresses nine (9) separate cost elements related to its underground storage operations, including:

1. New storage assets;
2. New general plant;
3. Other plant-related costs
4. Operating & maintenance expenses
5. Corporate administrative and general overheads
6. Unregulated business development and administrative costs
7. Cost of gas (fuel gas expenses and lost and unaccounted for gas)
8. Depreciation expense
9. Property tax

Each of these elements requires Enbridge to identify and compile the required input cost data, to select the direct assignment and/or cost allocation methods that are to be applied to the relevant costs, and to derive the costs associated with Enbridge's unregulated storage operations. As will be discussed in the next section, certain of these cost elements are allocated to Enbridge's unregulated storage operations on a one-time basis (as each new storage asset is added) while other cost elements are allocated to that business line on a monthly or annual basis using allocation factors that are updated periodically.

DATA SOURCES AND THE TIMING OF ENBRIDGE'S COST ALLOCATION PROCESS

Enbridge's on-going allocation of costs to its unregulated storage operations is premised upon, for the most part, the same sources of data that it utilizes to derive its total cost of service for regulated operations.

The timing of Enbridge's cost allocation process is presented in Schedule 3. There are two categories reflected in this Schedule, with costs allocated on: (1) an annual or monthly basis; and (2) a periodic basis. Schedule 3 presents the particular cost elements that comprise Enbridge's unregulated storage cost of service grouped according to these two categories. Details of the timing associated with Enbridge's cost allocation process are discussed in subsequent sections of this report.

FOUNDATIONAL ASPECTS OF ENBRIDGE'S COST ALLOCATION METHODS

As discussed earlier, Enbridge's unregulated storage operation has been created in recent years to function as an integral part of an integrated storage operation that served the entirety of its regulated storage requirements on a standalone basis at the time of the NGEIR Decision. On that basis, Enbridge has chosen to utilize an incremental costing approach as a foundation for its identification and assignment of new storage assets to either the regulated or unregulated storage operations. Under this approach, Enbridge reviews each of its asset additions to determine the cost drivers that explain the need for the new asset. These costs drivers include replacement or enhancement of existing assets, development of incremental capacity and/or deliverability, or some combination of these costs drivers. Because Enbridge has the specific operational knowledge of its storage operation to make this type of project-specific determination for each of its asset additions, it is unnecessary for Enbridge to rely upon a more generalized cost allocation method, such as a fully allocated costing approach, that presumes such assets cannot be directly attributed to either one of Enbridge's storage operations. More generally, a fully allocated costing approach is regularly relied upon in utility cost allocation studies to allocate the costs of common or joint-used assets because the utility does not have the knowledge or data to identify which specific assets should be assigned to particular rate classes over the life of the utility's gas system.

If a fully allocated costing approach was applied to Enbridge's total storage assets (regulated and unregulated businesses), its unregulated storage operation would be allocated between approximately $32 million (using an Annual Capacity factor) and $49 million (using a Daily Deliverability factor), or about $41 million if those two allocation factors were weighted equally in the allocation process. However, Black & Veatch does not view this result as properly reflecting the cost causative factors associated with Enbridge's asset additions over the 2007-2011 timeframe. As will be discussed in greater detail later in this report, under Enbridge's current cost allocation method for its new storage assets, its unregulated storage operation has been assigned about $84.4 million in net storage plant through the end of 2011. In Black & Veatch's view, it is appropriate for Enbridge to utilize an incremental costing approach for its new storage assets because it best reflects the cost causative factors which drive the level of asset costs incurred by Enbridge to serve its unregulated storage market.

STORAGE-RELATED ASSETS

This section describes the evolution of Enbridge's storage operations since the NGEIR Decision and the treatment of Enbridge's new asset additions and asset retirements within its cost allocation process for storage operations.

Enbridge's Regulated Storage Assets

At the time of the NGEIR Decision, the 2007 gross value of the storage assets supporting Enbridge's existing regulated storage operation was approximately $261 million, with a net plant investment of about $175 million. Since 2007, Enbridge has made modest investments in its regulated storage operations primarily to replace or recondition facilities that have through age, use, or obsolescence, come to the end of their useful lives. In addition to these "maintenance-related" projects, Enbridge also has had to make capital expenditures for its regulated storage operations to ensure continued compliance with safety, environmental, and technical requirements. Examples of such expenditures recently made by Enbridge include: noise and exhaust emission enhancements to compressor facilities and improvements to its gas measurement and gas inventory observation facilities.

Table 1 below presents Enbridge's net plant in service for its regulated storage operations for the years 2007 through 2011.

Table 1
Enbridge Gas Storage Assets – Regulated Operation
Net Plant Balances at Year End
($ millions)

ASSET DESCRIPTION	PLANT ACCOUNT	2007	2008	2009	2010	2011
Land & Land Rights	450/451	22.5	21.4	20.4	21.1	20.2
Structures & Improvements	452	6.5	6.5	6.5	9.6	9.5
Wells	453	12.4	12.4	13.4	20.7	22.5
Well Equipment	454	3.8	4.0	4.3	4.6	4.3
Field Lines	455	27.6	26.8	26.7	25.9	38.4
Compressor Equipment	456	54.3	56.7	59.4	60.8	61.5
Measuring & Regulating Equipment	457	7.3	7.0	6.8	6.6	6.2
Base Pressure Gas	458	40.8	40.8	40.8	40.9	40.9
Total		$175.2	$175.6	$178.3	$190.2	$203.5

The costs of any other investments made by Enbridge over the 2007-2011 timeframe that were designed to add storage capacity and deliverability to its existing gas storage system were all assigned to Enbridge's unregulated storage operations.

Enbridge's Unregulated Storage Assets

In 2007, Enbridge began its investment program to add capacity and deliverability to support its newly created unregulated storage operation. From that time through 2011, Enbridge has invested approximately $88 million in gross plant additions in four major storage-related capital programs. These programs have included the drilling of additional wells into Enbridge's existing storage pools and the installation of additional pipelines, compression, gas dehydration, and measurement capacity. Some of the additional metering capacity has been added at the custody transfer point into Union's gas transmission system at Dawn and some has been created at a new custody point into the Vector pipeline system.

As a result of these capital programs, Enbridge has created new storage capacity and deliverability that it has offered to the competitive gas market. In total, these projects have resulted in the development of about 12.2 Bcf of total storage capacity and incremental withdrawal capability of 400 MMcfd at the end of 2011 (see Schedule 1). Without these capital investments made by Enbridge, none of its new storage capacity would be available to provide services to its unregulated storage market.

Table 2 below presents Enbridge's net plant in service for its unregulated storage operations for the years 2007 through 2011.

Table 2
Enbridge Gas Storage Assets – Unregulated Operation
Net Plant Balances at Year End
($ millions)

ASSET DESCRIPTION	PLANT ACCOUNT	2007	2008	2009	2010	2011
Land & Land Rights	450/451			0.4	1.1	1.1
Structures & Improvements	452			0.0	0.0	0.0
Wells	453		3.9	7.2	10.0	9.6
Well Equipment	454		0.0	0.0	0.0	0.0
Field Lines	455	1.3	8.5	14.6	14.6	14.2
Compressor Equipment	456	7.1	9.9	11.9	20.1	20.6
Measuring & Regulating Equipment	457		0.0	0.4	0.3	0.3
Plant Not Classified (1)	458		14.1	12.8	3.6	38.6
Total		$8.4	$36.4	$47.3	$49.7	$84.4

(1) 2011 amount related to the capitalization of Project Nexus – a gas storage expansion project

Based on Enbridge's cost allocation method and the results reflected in Tables 1 and 2, approximately 29% of Enbridge's total net storage plant (as of December 31, 2011) has been assigned to its unregulated storage operation.

To understand and verify the manner in which these plant account balances were derived, Black & Veatch reviewed Enbridge's detailed plant accounting data for its gross plant and accumulated depreciation reserve entries from 2007 through 2011. Schedule 4 presents the annual derivation of Enbridge's net plant balances for its unregulated storage operations. This analysis verified that Enbridge's net plant balances presented in Table 2 were accurate and that they could be replicated from the more detailed plant information.

New Storage Assets

Enbridge has developed and implemented a cost allocation process that assigns the cost of its storage investments to its regulated and unregulated storage operations. The method is premised upon the proper reflection of cost causative principles. Specifically, Enbridge has developed the following investment categories to facilitate the grouping of its storage-related investment according to the factors which cause each investment to be made:

1. Replacement of Existing Storage Assets
2. Development of Incremental Storage Capacity
3. Replacement of Existing Storage Assets with a Capacity Enhancement Component

4. General Storage Plant

Each of these investment categories are described in further detail below. It should be noted that the above-described process requires the allocation of individual assets in order for Enbridge to create and maintain on a going forward basis the proper plant accounting records at the individual asset level for its unregulated storage operations.

Replacement or Enhancement of Existing Storage Assets

These projects consist of storage-related assets that are installed to replace Enbridge's existing assets supporting its storage operations. The nature of these projects serve to maintain the facilities and service capabilities whether they completely replace the asset, recondition the asset, or bring the asset into regulatory or environmental compliance. In all cases, the capital costs of these new facilities are directly assigned to Enbridge's accounts and/or entity of the original assets.

Black & Veatch reviewed Enbridge's projects in this category and confirmed that the capital costs of each asset addition were treated in a manner consistent with its current cost allocation methods. As an example, Enbridge's "K708 Compressor Power Cylinder Liner Replacement" project was undertaken in 2011 to replace the cylinder liners on one of its compressor engines at Tecumseh. These liners deteriorate over time from wear and must be replaced, which means that this is a "maintenance capital" type project. Since this compressor engine was originally installed to meet the storage needs of Enbridge's regulated storage operation, Enbridge concluded that it was appropriate to directly assign the cost of this new asset to the regulated utility business.

Another example of an asset replacement or enhancement project is Enbridge's drilling of the Tecumseh Seckerton #20 pressure observation well in a location adjacent to the Seckerton storage pool. The drilling of this well, and others, was recommended by reservoir consultants to Enbridge. The well may confirm the presence of porous rock zones in proximity to the storage pool, and the presence of gas volumes in those zones that would indicate communication with the pool. The well enhances Enbridge's understanding of the Seckerton storage pool and helps to raise the quality of its gas inventory management to a standard that is consistent with storage industry practice. Because the well enhances Enbridge's understanding of the Seckerton storage pool, which is a regulated asset, its cost has been charged to the regulated storage operation.

Based on its review of these projects, Black & Veatch agrees with the costing treatment of these assets.

Development of Incremental Storage Capacity

These projects consist of storage-related assets that are installed to provide Enbridge with new storage capacity or deliverability. Since the storage needs of Enbridge's regulated utility business continue to be fully satisfied by the storage-related assets (and third-party storage) that existed at the time of the NGEIR Decision, the capital costs of these new facilities are directly assigned to Enbridge's unregulated storage operation.

Black & Veatch reviewed Enbridge's projects in this category and confirmed that the capital cost of each asset addition was treated in a manner consistent with its current cost allocation methods. As an example, Enbridge's "Drilling of TKC 61H" project was undertaken to drill a new storage injection/withdrawal well. This well was a relatively high cost, horizontal well drilled into

Enbridge's Mid-Kimball storage pool. Since this well was drilled to satisfy the incremental storage capacity needs of Enbridge's unregulated storage operation, Enbridge concluded that it was appropriate to directly assign the cost of this new asset to its unregulated storage business.

Another example is Enbridge's "Ladysmith Gathering Pipeline" project which was undertaken to provide greater gas flow capabilities into and out of the Ladysmith storage pool, while making available some capacity on the Wilkesport gathering pipeline. This project optimized Enbridge's storage system, thereby, creating a greater level of storage capacity at Enbridge's custody transfer points to serve its unregulated storage market. As a result, Enbridge concluded that it was appropriate to directly assign the cost of this new asset to its unregulated storage business.

Based on our review of these projects, Black & Veatch agrees with the costing treatment of these assets.

Replacement of Existing Assets with a Capacity Enhancement Component

These projects consist of storage-related assets that are installed to replace Enbridge's existing assets and to provide incremental storage capacity or deliverability. For example, it may be necessary for Enbridge to replace a utility asset at the end of its useful life, but where the replacement asset is sized to provide additional capacity beyond that of the original asset. Importantly, the replacement of the asset is driven by the fact that it is no longer technically capable of providing the service for which it was intended and that Enbridge needs to replace the asset to maintain the level of storage service required by its regulated utility customers.

Under this scenario, Enbridge's regulated utility operation would be charged the portion of the capital costs that it would have incurred if it were to have replaced the asset on a like-for-like basis. And, on that basis, its unregulated storage operation would be charged for the incremental costs that would have resulted from the higher capacity asset. This would include both the cost of the incremental capacity and the cost of any of the system design changes that might have been required to accommodate the different asset. In other words, the portion of the total asset cost that will be booked to Enbridge's regulated storage operation will be no more, and may be less, than would have been incurred had the replacement asset been sized simply to replace the original asset.

Conversely, in a scenario where the asset is not at the end of its useful life, but where its replacement is driven by the operational needs of Enbridge's unregulated storage operation, then it would be charged for the entire cost of the replacement. Finally, we understand that the relative proportions of the replacement assets will be noted by Enbridge in the asset accounts of both its storage operations.

Black & Veatch reviewed Enbridge's projects in this category and confirmed that the capital cost of each asset addition was treated in a manner consistent with its current cost allocation methods. As an example, Enbridge's "Replace Corunna and Seckerton Pool Gathering Pipelines" project was undertaken after a review of the existing wellhead and gathering line facilities of the Corunna and Seckerton storage pools to determine their appropriateness for the delta pressuring of the pools to create additional unregulated capacity. This review revealed that those facilities would have to be replaced to allow for the needs of Enbridge's higher pressure, unregulated storage service. Since this replacement would not have otherwise occurred because the existing facilities were suitable to continue to provide storage services to Enbridge's regulated utility customers, Enbridge concluded that the entire cost of this replacement should be assigned to its unregulated storage operation. Based on our review of this project, Black & Veatch agrees with the costing treatment of these assets.

Another example is Enbridge's "Pool Metering Upgrades" project which was undertaken to provide more accurate measurement of total pool volumes, energy content, and injection/withdrawal volumes. Enbridge was required to replace its older metering technology with current technology metering equipment. At the same time, certain gathering line changes were required to accommodate the storage capacity and deliverability needs of the unregulated storage operation, so the total cost of the project was much higher than if only the metering facilities were replaced.

To reflect the cost consequences of this configuration of facilities, Enbridge designed and estimated the cost of this project assuming two design scenarios – with and without the incremental asset requirements of the unregulated storage business. The incremental costs of the project were caused by higher pressure-rated materials, additional growth elements in the facilities design, and the different physical configuration of the gathering facilities supporting the unregulated storage operation. As a result, Enbridge concluded that it was appropriate to assign the replacement cost of the metering facilities to its regulated storage business, with all other costs of the project assigned to its unregulated storage operation.

Although there are still certain project costs that have yet to be incurred, the estimated cost at completion is expected to be about $36.2 million. Of this amount, approximately $21.0 million or 58% of the total project costs will be charged to Enbridge's regulated utility business with the balance of approximately $15.2 million or 42% of the total project costs to be assigned to its unregulated storage operation. Black & Veatch agrees with Enbridge's expected costing treatment of these assets.

General Storage Plant

General plant assets consist predominantly of structures such as office and utility buildings, warehouses, sheds, and parking lots that do not directly support the capacity and deliverability of Enbridge's storage operations. Under Enbridge's current cost allocation process, if the general storage plant asset is designed to meet an incremental need of either of its two storage operations, Enbridge will assign the entire cost of that asset addition to the particular operation that had the direct need for that asset. If the project is driven more by the general needs of its integrated storage operation, Enbridge will allocate the cost of that asset to both operations based on an allocation factor that best reflected the cost causative characteristics of the facility's design and intended purpose.

During the course of this project, Black & Veatch had a number of discussions with Enbridge staff who are involved in the day-to-day operations, asset investment evaluations and decisions, and accounting treatment of its unregulated storage operations. One of the discussion topics was the appropriate cost allocation treatment of Enbridge's general storage plant. Enbridge has not had an asset addition to its general storage plant since the NGEIR Decision so it did not have any real world examples to consider for cost allocation purposes. From our discussions, we were of the view initially that Enbridge would likely directly assign to its regulated storage operation the cost of any replacement of, or enhancement to, its general storage facilities simply because the original asset had existed previously to only support the regulated storage operations.

Our further discussions also indicated that Enbridge does have under construction currently a storage (warehouse) building located at its Sombra Compressor Station. The Sombra Storage Building project will support Enbridge's integrated storage operation and will be used to store Glycol, compressor parts, and other storage-related materials. Black & Veatch understands that this planned asset addition was originally viewed by Enbridge as a facility which solely supported its regulated storage operation. On that basis, Enbridge intended to assign the entire capital cost of this asset to its regulated storage operation. After further evaluation of the purpose and expected utilization of this facility, Enbridge has revisited the assignment of capital costs for this project. The Sombra facility is not an asset replacement project and it has been sized to provide some additional space to house certain materials that are required for the unregulated storage operation. As a result, the capital cost of this facility should be assigned to both storage businesses using an allocation basis that reflects the joint use of the facility.

More generally, the treatment of the Sombra facility for cost allocation purposes has caused Enbridge to consider revising its current cost allocation process for storage-related assets. One option would be to assign a portion of the asset to each of Enbridge's two storage businesses by developing an allocation factor which is based upon the amount of storage space required for each storage business. Another option would be to treat the capital costs as an overhead item and to allocate those costs on a corporate-wide basis as a function of each cost center's direct costs. Enbridge has proposed to treat such assets as "Corporate General Plant" as other similar assets are treated within the Enbridge organization. We understand that Enbridge normally treats Corporate General Plant as an overhead cost element and apportions such costs across its various cost centers through its A&G overhead factors. Under that method, Enbridge's unregulated storage operation would share in the cost of this facility in the same way it does for all of Enbridge's other general plant facilities. Based on our understanding of that process, Black & Veatch believes that Enbridge's proposed method is a reasonable basis for the cost allocation treatment of general storage plant.

Enbridge's Capital Project Assessment Process

Schedule 5 presents a flowchart of the assessment process that Enbridge follows to assign the costs of storage-related capital projects to its regulated and unregulated storage operations. The decision criteria in this flowchart reflects the cost attribution characteristics described above for each category of Enbridge's storage assets, including its proposed treatment of general storage plant. Black & Veatch recognizes that the process reflected in Schedule 5 has become more formalized in recent times as Enbridge has invested in each type of storage asset and gained greater insights into the factors causing the investments to be made in these assets. One proposed addition that Black & Veatch recommends to Enbridge's capital project assessment process is to include the gas storage characteristic of deliverability in the description of projects that should be charged directly to Enbridge's unregulated storage business.

Based on our review of individual new storage assets added by Enbridge since 2007 to support its regulated and unregulated storage operations, Black & Veatch concludes that Enbridge has applied its cost attribution process to new storage assets in a consistent manner. This conclusion was based upon our evaluation of the examples of storage assets presented above (and others) within the context of Enbridge's current capital project assessment process reflected in Schedule 5.

Other Plant-Related Costs

For each of its storage-related projects, Enbridge reflects a total cost level that includes all of the materials and third-party service costs that are incurred in the design, construction, and commissioning of the facility. In most cases, the project will also require time and effort from Enbridge staff, with much of that being provided from its Gas Storage Operations staff located near its Tecumseh storage operation. In addition to these costs, each project also is charged for Interest during Construction ("IDC") and administration and general corporate overheads.

These cost components are described below:

Internal Labor

All Enbridge staff members working directly on each capital project maintain time sheets that accumulate the time spent on the project. Those time sheets are processed on a regular basis, and the time is charged at the hourly equivalent rate for that staff member.

Corporate Administrative and General ("A&G") Overheads

Enbridge charges corporate A&G costs to the new storage assets of its unregulated storage operation in the same manner as it does for its O&M costs (as will be described later). The hourly salary rates for Enbridge staff working on those projects are grossed-up to include corporate A&G and an amount associated with the expected performance-based payout inherent in Enbridge's employee compensation plan. Together, these amounts result in an overhead factor of approximately 65% to 70% which is applied to each staff member's base salary level.

Contractor and Materials

All third-party services and materials costs related to Enbridge's unregulated storage projects are charged directly to its unregulated storage accounts.

Interest During Construction ("IDC")

Enbridge assesses an IDC charge to all unregulated storage projects in the same manner that it does for its utility capital projects.

STORAGE-RELATED EXPENSES

With the commencement of its unregulated storage operations, and the operation of its larger, integrated storage facilities, Enbridge's total O&M costs have increased over time as its unregulated storage operation has grown. There are additional storage-related facilities to operate and maintain, and more gas volumes being transacted. Some specific O&M costs have increased generally, more or less in proportion to the increase in storage activity; while others have increased only marginally, or not at all. As additional capacity and deliverability is added to Enbridge's integrated storage operations in the future, it is understood that these costs may increase in a stair step manner in recognition of the added manpower requirements that could be caused by Enbridge reaching a higher level of storage activity.

Table 3 below presents Enbridge's total storage O&M costs for its regulated storage operations for the years 2007 through 2011. Table 4 which follows presents Enbridge's total storage O&M costs for its unregulated storage operations for the years 2007 through 2011.

Table 3
Enbridge Gas Storage – O&M Costs
Regulated Storage Operation

EXPENSE CATEGORY (1)	2007	2008	2009	2010	2011
Labor	$3,361,251	$3,574,771	$3,607,253	$3,835,016	$4,299,598
Supplies	$1,061,065	$1,152,423	$1,022,099	$1,348,299	$1,365,079
Consulting Services	$1,480,086	$1,416,565	$1,468,205	$2,146,386	$1,482,801
Other Operating Expenses	$2,314,434	$2,223,109	$2,501,334	$2,653,088	$2,355,530
Property Taxes	$1,321,560	$1,180,933	$1,331,352	$1,425,708	$1,611,240
Labor Credits and Other	($1,044,216)	($1,279,375)	($1,400,056)	($2,036,650)	($2,358,964)
Total	$8,494,180	$8,268,426	$8,530,187	$9,371,847	$8,755,284

(1) Excludes A&G Overhead amounts

Table 4
Enbridge Gas Storage – O&M Costs
Unregulated Storage Operation

EXPENSE CATEGORY (1)	2007	2008	2009	2010	2011
Labor	$143,821	$117,253	$506,108	$491,619	$391,669
Supplies	$136	$483	$19,652	$165	$2,687
Consulting Services	$85,016	$19,413	$166,735	$183,663	$180,294
Employee Expenses	$10,058	$14,965	$27,785	$752	$29,314
Other Operating Expenses	$6,667	$41,593	$404,052	$1,083,138	$1,401,631
Property Taxes (1)		$156,000	$73,656		
Subtotal	$245,698	$349,707	$1,197,988	$1,759,337	$2,005,595
Labor Credits and Other	($8,895)	$10,995	($75,167)	($51,740)	($59,114)
Total	$236,803	$360,702	$1,122,821	$1,707,597	$1,946,481
Direct Assignment	$230,136	$319,109	$718,769	$624,459	$544,850
Allocated Amount	$6,667	$41,593	$404,052	$1,083,138	$1,401,631
Total	$236,803	$360,702	$1,122,821	$1,707,597	$1,946,481

(1) An allocated amount is included in Other Operating Expenses in 2010 and 2011

To determine an appropriate cost allocation basis for its O&M costs, Enbridge evaluated each of its cost categories to establish a relationship between the various service requirements of storage and the costs incurred by Enbridge in serving those requirements (i.e., what are the cost drivers?). Unlike the asset side of Enbridge's storage operations, where a clearer determination could be made of which of Enbridge's two storage operations caused the new asset addition, O&M expenses are more generalized in nature, and in many cases, they support the entirety of Enbridge's integrated storage operation. This fact makes it difficult to determine with certainty which of Enbridge's two storage operations cause these costs to be incurred. As a result, most of Enbridge's O&M expenses are allocated and shared on the basis of the relative proportions of the total storage capacities and, in some cases, the actual storage activity of its regulated and unregulated storage operations.

Enbridge derives storage-related expenses for its unregulated storage operations on a monthly basis to reflect the latest operating activity supporting that business. Enbridge first identifies the costs of certain storage-related activities that can be directly attributed or assigned to its unregulated storage operations. Enbridge's unregulated storage business has an Unregulated Storage Group that is dedicated to managing and administering all aspects of that business. All other activities and associated costs which support Enbridge's integrated storage operations must be allocated between its regulated and unregulated storage operations. An assessment of the appropriate costing treatment was made by Enbridge for each of the various cost elements that supports Enbridge's storage operations. Each of Enbridge's cost elements that support (either directly or indirectly) its unregulated storage operations, and the associated allocation methods, is described below.

Storage Operations

Enbridge incurs certain operating costs that can be directly identified with its unregulated storage operations. These activities consist of staff time and a variety of other expenses associated with Enbridge's Unregulated Storage Group described earlier. The costs of these activities are charged to a cost center that is specific to the unregulated storage business.[9]

For cost allocation purposes, Enbridge has determined that the costs of its storage operations can either be classified as fixed or variable in nature. Enbridge has defined fixed costs as those that do not vary with the levels of storage activity, and variable costs as those that do vary with activity. This approach is similar to the designation of demand and commodity costs as used in a utility's traditional cost allocation study. This cost classification process is dependent upon the degree to which the particular cost is observed to vary with Enbridge's storage activity. If a particular cost does not change materially with the level of actual storage activity, then Enbridge classifies that cost as 100% fixed. Conversely, for costs that do vary materially as the level of actual storage activity changes, Enbridge classifies these costs as 100% variable. Examples of variable costs are other materials such as compressor and crankcase oil, glycol, and outside services such as electricity.

Enbridge has evaluated each of its cost elements to determine how the particular cost should be classified. In most cases, it was a straightforward process for Enbridge to determine definitively

[9] Enbridge Gas Distribution - Cost Centre 25371 – Unregulated Storage

that the cost element was fixed in nature. For certain other cost elements, Enbridge was required to apply management judgment by those staff members closest to the underlying activities to determine the relative proportion of costs that were fixed and variable in nature.

The operating expenses that are deemed to be relatively fixed are allocated between Enbridge's regulated and unregulated storage operations based upon their relative share of Enbridge's total available storage capacity. This means that, as the unregulated storage business grows, the unregulated business will be charged for an increasing share of Enbridge's fixed storage operating costs.

For those operating costs that vary with the levels of storage activity, Enbridge allocates such costs using the actual costs incurred in each month, and the relative share of the total actual storage activity for the regulated and unregulated storage operations for that same month. In that way, Enbridge's unregulated storage business, which may exhibit a more volatile activity profile than the more traditional use of storage by the regulated utility customer, would pay a higher share of these variable costs in months when its customers required a disproportionately greater level of storage activity.

To better understand and verify how Enbridge conducts its above-described cost allocation process, Black & Veatch analyzed the storage-related expenses incurred by Enbridge each month during calendar year 2011 and the level of costs that was directly assigned or allocated to its unregulated storage operations. To illustrate the cost allocation process that Enbridge follows, Schedule 6 presents a series of detailed storage cost accounting sheets for calendar 2011 and for the month of November 2011 (which reflect expenses that are charged in December). Page 1 of Schedule 6 presents a summary of the allocation of O&M costs to Enbridge's unregulated storage operation for 2011. There are four Cost Centers associated with Enbridge's gas storage operations: (1) Storage Administration - 25121; (2) Storage Operations - 25122; (3) Storage Maintenance - 25123; and (4) Field Maintenance - 25124. The total allocated amount of $1,401,567 presented on page 1 of Schedule 6 is brought forward to Table 4 presented above.[10]

For each month, there are four (4) Operating Cost Reports by Cost Center that reflect the allocation of costs between Enbridge's regulated and unregulated storage operations (see Pages 2-5 of Schedule 6). Each sheet details the allocation of costs by individual cost element, the derivation of the fixed and variable allocation factors based on the shares of storage capacity and storage activity, respectively, and the resulting total costs to be charged to Enbridge's unregulated storage operation.

At the end of each month, Enbridge charges the total allocated costs for each of these Cost Centers to its unregulated storage operation through adjustments to its General Ledger Journal, which results in the inclusion of these costs in the December 2011 Operating Cost Report[11] for Enbridge's

[10] An unexplained discrepancy of $64 exists between the amounts recorded in Enbridge's Monthly Operating Cost Reports for 2011 (see page 1 of Schedule 6) and the total amount recorded in the "Other Operating" line entry (70899) in its Operating Cost Report for 2011 for Cost Center 25371 – Unregulated Storage (see page 6 of Schedule 6).

[11] There is a one-month lag in the booking of the allocated storage costs in the Operating Cost Report of Enbridge's unregulated storage operation.

unregulated storage operation. Page 6 of Schedule 6 is a copy of the Operating Cost Report for December 2011 for Enbridge's unregulated storage operation, which shows the inclusion of the allocated storage costs for calendar 2011 in the line identified as "70899 Other Operating" under the column "Year to Date – Actual."

Black & Veatch believes that the manner in which Enbridge allocates costs in this category to its two storage operations should be reflective of the cost causative factors that give rise to these costs. While Black & Veatch agrees that storage capacity (or space) and storage activity are two important attributes of a utility's storage operations, storage deliverability also is an important cost driver. In its past filings, Enbridge has not explicitly recognized storage deliverability in its cost allocation methods. When Black & Veatch questioned Enbridge concerning why it did not classify storage-related O&M costs according to the cost classification categories of Deliverability and Space that were used in its Fully Allocated Cost Study, Enbridge responded as follows:

> "Because of the nature of the unregulated storage services, and the likelihood that gas volumes for unregulated customers would be cycled several times in a year, it was felt that activity was a fairer basis for cost allocation. A deliverability classification, as used for the more traditional, single cycle needs of the utility customers, would have recognized the higher deliverability characteristics of the current unregulated storage business but would not have recognized the multiple-cycling nature of the unregulated storage contracts. It is felt that basing the allocation on activity, and not deliverability, would capture both the higher deliverability and multiple-cycling cost implications of these services."

Black & Veatch understands Enbridge's response and agrees with the view that it is more appropriate to allocate certain of these costs using an allocation factor based on storage activity because it better reflects the storage requirements of its unregulated storage operations. However, Black & Veatch does not agree with the conclusion that storage activity also serves as a good proxy for storage deliverability. In Enbridge's most recent fully allocated cost study, it classified Tecumseh Gas' storage-related costs, and the costs based on contract arrangements with Union, according to three distinct types of service:

1. An annual component for space or capacity
2. A variable component (activity) for each unit of gas injected into or withdrawn from storage
3. A peak component (deliverability) for the maximum daily rate at which the gas may be withdrawn from storage.[12]

Enbridge classified approximately 40% of its total storage-related cost of service of Tecumseh Gas (excluding its commodity-related costs) as capacity ("Annual Demand") and 60% of these costs as deliverability ("Daily Demand").[13] Enbridge's subsequent allocation of these costs was performed recognizing the same 40/60 proportion of Annual Demand and Daily Demand. In contrast, Enbridge has allocated a much smaller percentage of costs to its unregulated storage operation

[12] EB-2006-08-25, Exhibit G2, Tab 1, Schedule 1, Page 16 of 26.
[13] EB-2006-08-25, Exhibit G2, Tab 7, Schedule 3, page 1.

using an allocation factor based on actual monthly storage activity compared to the 60% of costs described above which are allocated on a daily deliverability basis. Referring to pages 2 through 5 of Schedule 6, the total costs in November 2011 allocated on the basis of actual monthly storage activity equaled only about 6%, while the remaining 94% of the total costs were allocated on storage capacity. In Black & Veatch's opinion, this comparison shows that Enbridge's current cost allocation method which assigns storage O&M costs to its unregulated storage operation underemphasizes the cost driver of storage deliverability and overemphasizes the cost driver of storage capacity. As a result, Black & Veatch believes that this allocation method does not reflect the cost causative factors that are relied upon by Enbridge when classifying and allocating these same costs in its fully cost allocation study. Based on this situation, Black & Veatch conveyed to Enbridge during our discussions related to this study that it should consider changing its allocation factor for fixed storage costs to reflect a proper weighting of the cost drivers of capacity and deliverability.

As a result of Black & Veatch's discussions on this subject, Enbridge has re-examined each of the operating and maintenance expense categories for the four cost centers reflected in Schedule 6 and has determined that certain allocation factors should be revised to recognize storage deliverability as a distinct cost driver. As part of this re-examination, Enbridge also made minor revisions to the allocation treatment for certain costs that it believed were impacted differently by storage activity based on the nature of the business activity and with the recognition of deliverability as a cost allocation factor. Schedule 7 presents Enbridge's detailed storage cost accounting sheets for the month of August 2011 (which reflect expenses that are charged in September) with the revised allocation factors it proposes to establish for the assignment of fixed and variable expenses incurred to support its regulated and unregulated storage operations.

Black & Veatch has reviewed the revised cost allocation methods established by Enbridge for its storage operating expenses and concludes that they are reasonable and appropriate. Enbridge's cost allocation methods and cost allocation factors are reflective of the manner in which similar types of costs are treated in its fully allocated cost of service study and the judgments of the staff who are regularly involved in the day-to-day management and operations of its gas storage businesses.

One additional minor issue that was identified by Black & Veatch pertained to Enbridge's use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center (see page 2 of Schedule 6). Enbridge first reduces the actual total labor costs in this area by 5% (a 95% Applicable Share amount) to recognize that one FTE in the business group does not provide any services to the unregulated storage business. As discussed earlier, Enbridge's Unregulated Storage Group provides dedicated managerial and administrative support to the unregulated storage business. As such, Enbridge views an allocation of 100% of the labor costs of the Storage Administration Cost Center as creating an over-allocation of these costs to its unregulated storage operation.

Our concern is that if Enbridge relies upon a fully allocated costing basis to assign O&M costs to its unregulated storage operation, it is inappropriate to first eliminate certain costs from the allocation process. This is because the validity in utilizing a generalized allocation factor is premised upon it being applied to all costs being assigned. The application of the particular allocation factor (e.g., 11% for storage capacity) presumes that a portion of the time spent by all staff represents a fair allocation of total costs between the two storage businesses, irrespective of the specific activities on any one staff member. While Enbridge believes that a particular staff member does not spend 11% of the workday supporting its unregulated storage operation, its use of a fully allocated costing method also means that Enbridge has implicitly accepted the premise that staff may spend a greater or lesser amount of time than the 11% level inherent in the allocation factor, but that overall, each of the staff spends an average of 11% on unregulated storage activities.

While Black & Veatch understands that this particular element of Enbridge's current cost allocation process causes a slight reduction in the level of costs assigned to its unregulated storage operation, it does compromise the conceptual basis for adopting a fully allocated costing method for these costs. As a result, Black & Veatch believes that this minor exception to the cost allocation process should be addressed by Enbridge on a going-forward basis by eliminating its "Applicable Share" adjustment. Based on this situation, Black & Veatch conveyed to Enbridge during our discussions related to this study that its use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center should be eliminated from its current cost allocation process on a going-forward basis.

We understand that Enbridge has reviewed our explanation of this situation and has proposed to eliminate this adjustment from its current allocation treatment of storage-related operating expenses. Schedule 7 shows that the "Applicable Share" adjustment will no longer appear in Enbridge's monthly Operating Cost Reports.

Corporate Administrative and General Overheads

Enbridge also allocates A&G overhead costs to its unregulated storage operations in the same way that it does for the operating costs incurred by its regulated storage activities. An hourly A&G overhead amount is determined for each Full-Time Equivalent ("FTE") staff member, with those costs treated as a premium to the hourly cost of the FTEs involved in Enbridge's unregulated storage activities.

These overhead costs include a broad range of corporate costs and services such as finance and business services, customer support, regulatory, legal and corporate services, human resources, and engineering, as well as a rate of return on, and the depreciation expenses for, buildings, office furniture and equipment, telecom equipment, and information technology/software assets. In addition to these overhead costs, Enbridge's cost allocation process also includes the expected cost of its performance-based pay incentive for storage operations staff.

The allocation of these overhead costs to Enbridge's unregulated storage operation has the effect of increasing the base labor costs by 65% to 70%, which is reflected on page 2 of Schedule 6 under the "Overhead Rate" column. The calculation and inclusion of these overhead amounts is an integral part of Enbridge's monthly allocation process for its Tecumseh storage operations.

Unregulated Business Development and Administration Costs

As a participant in the unregulated storage industry, Enbridge incurs other costs that are specific to the strategic development, management and operation of the business. These costs are charged directly to the set of accounts that are kept for the unregulated business. Among these is the cost of the dedicated management and staff of the unregulated storage business, the cost of Gas Control services in Edmonton and the cost of any professional services required, such as legal counsel and third party technical consultants.

These resources are necessary to stay current with gas storage markets, identify storage service opportunities and their feasibility and to manage the contractual relationships that underlie the commercial basis for the un-regulated storage business. These costs are charged directly to the accounts of the unregulated storage business through the normal payroll, financial and A/P systems of Enbridge. As such, there are no business development and administrative costs in this category that is incurred on behalf of Enbridge's regulated storage operations.

Fuel Gas

Enbridge assigns a portion of the cost of gas it incurs to operate its gas storage operations at Tecumseh to its unregulated storage operations. This is accomplished by determining the actual storage activity for Enbridge's unregulated storage operations and applying that amount to the previous October's Quarterly Rate Adjustment Mechanism ("QRAM") reference price of gas. Enbridge's current Fuel Ratio charged to its unregulated storage customers is 0.35%.

Lost and Unaccounted For Gas

Enbridge assigns the cost of Lost and Unaccounted for Gas ("LUF") to its unregulated storage operations by applying an "in-kind" charge to its unregulated storage customers' capacity and activity levels. This charge uses the same LUF replacement factor that has been approved by the Board for Enbridge's regulated utility customers. We understand that Enbridge maintains a separate LUF factor that is specific to its gas storage operations.

Schedule 8 summarizes the cost allocation treatment for Enbridge's cost of gas components.

Depreciation Expense

Annual depreciation rates for Enbridge's underground storage assets were approved by the Board in RP-2002-0133. Table 5 below presents the annual depreciation rates for Enbridge's unregulated underground storage operations.

Table 5
Enbridge's Annual Depreciation Rates for Unregulated Storage Assets

ACCOUNT NUMBER	ACCOUNT DESCRIPTION	ANNUAL DEPRECIATION RATE
451	Land Rights	2.10%
452	Structures & Improvements	2.60%
453	Wells	4.60%
454	Well Equipment	3.10%
455	Field Lines	2.60%
456	Compressor Equipment	2.20%
457	Regulating Equipment	3.60%

Depreciation expense (and the associated accumulated depreciation reserve) is calculated at the individual asset level using the annual rate that is applicable to the entire asset class. Enbridge's depreciation expense is posted to a separate general ledger account. The 2011 depreciation expense for Enbridge's unregulated storage assets was approximately $1.37 million.

Property Taxes

Enbridge currently assigns a portion of its storage-related property taxes to the unregulated storage business through the cost allocation process utilized in its Storage Administration Cost Center (25121). As shown on page 1 of Schedule 7, under the line "70701 – Property Taxes," Enbridge proposes to assign this cost element to its unregulated storage operation on the basis of its Annual Capacity allocation factor (40%) and its Deliverability allocation factor (60%).

Schedule 9 summarizes the cost allocation treatment for Enbridge's depreciation expense and property taxes.

FINDINGS AND RECOMMENDATIONS

Based upon Black & Veatch's review of Enbridge's storage allocation process, methodology, and results, the conceptual underpinnings and resulting methodologies upon which Enbridge's cost allocation process are generally well-conceived and reasonable in their treatment of storage-related plant and expenses. However, there are a few components of Enbridge's current cost allocation methods that Black & Veatch believes should be changed to better recognize the underlying cost causative factors of Enbridge's storage operations. As described previously, Enbridge has considered Black & Veatch's discussions on this topic and has proposed to revise certain of its current cost allocation methods for the following cost elements:

- **New General Storage Plant**
    1. Enbridge proposes to adopt the cost allocation treatment for new general plant depicted in Schedule 5 and to apply this method to the cost of its Sombra warehouse facility once it is completed and placed into service.

- **Storage Operations**
    1. Enbridge proposes to change its cost allocation factor for fixed storage costs to reflect a proper weighting of the cost drivers of annual capacity and deliverability, and has made minor modifications to the portion of costs it classifies as variable in nature.

    2. Enbridge proposes to eliminate from its current cost allocation process the use of an "Applicable Share" adjustment to certain costs included in the Storage Administration Cost Center (see page 2 of Schedule 6).

In addition, the manner in which Enbridge has presented its separation of costs between its regulated and unregulated storage operations in its past ESM Filings before the Board[14] does not in all cases provide a sufficient level of detail and explanation to allow an outside party to understand,

[14] See Enbridge's evidence filed in EB-2010-0042 and EB-2011-0008.

trace, and verify the underlying assumptions of the cost allocation methodology, computational processes, and to independently confirm the results.

As a result of this finding, Black & Veatch recommends the following enhancements to Enbridge's computational process and evidentiary presentation:

1. Establish more robust documentation that readily allows the reader to clearly trace how Enbridge's regulated and unregulated storage costs are developed, which should include providing clear references for the cost allocation methods used in the calculation of the costs of Enbridge's unregulated storage operations. Black & Veatch believes that certain of the Schedules presented in this report should be incorporated into Enbridge's future evidentiary presentations before the Board on this subject.

2. Provide additional details to be able to trace Enbridge's elimination from its Utility Income of each particular expense item (e.g., gas costs, O&M expenses, property taxes, and depreciation expense) associated with Enbridge's unregulated storage operation, and the computational details to derive each eliminated amount.[15]

3. The manner in which Enbridge splits the cost of new storage assets that replace existing storage assets with a capacity enhancement component between its regulated and unregulated storage operations (e.g., Enbridge's "Pool Metering Upgrades" project) should be detailed so that the basis for the determination of the cost split can be readily understood by an outside party.

[15] See EB-2011-0008, Exhibit B, Tab 1, Schedule 4, pages 1-4.

ENBRIDGE GAS DISTRIBUTION INC.

Underground Storage Facilities - Operational Characteristics (1)

	2007	2008	2009	2010	2011
Annual Capacity (Bcf)					
In-Franchise (2)	91.7	91.7	91.7	91.7	91.7
Ex-Franchise (3)	6.7	6.7	6.7	6.7	6.7
Subtotal	98.4	98.4	98.4	98.4	98.4
Unregulated	0.0	2.2	4.2	8.7	12.2
Total	98.4	100.6	102.6	107.1	110.6
Daily Withdrawal Commitments (Bcfd)					
In-Franchise (2)	1.74	1.74	1.74	1.74	1.74
Ex-Franchise (4)	0.19	0.19	0.19	0.19	0.19
Subtotal	1.93	1.93	1.93	1.93	1.93
Unregulated	0.0	0.157	0.269	0.359	0.401
Total	1.93	2.09	2.20	2.29	2.33
Injection/Withdrawal Activity (Bcf)					
Regulated	0	140.11	179.02	163.85	173.28
Unregulated	0.0	11.97	28.28	13.65	15.49
Total	0.00	152.08	207.30	177.50	188.77
Storage Turnover Rate (5)					
Regulated	0	1.4	1.8	1.7	1.8
Unregulated	0.0	5.4	6.7	1.6	1.3
Total	0.0	1.5	2.0	1.7	1.7

Notes:

(1) Includes Crowland Storage

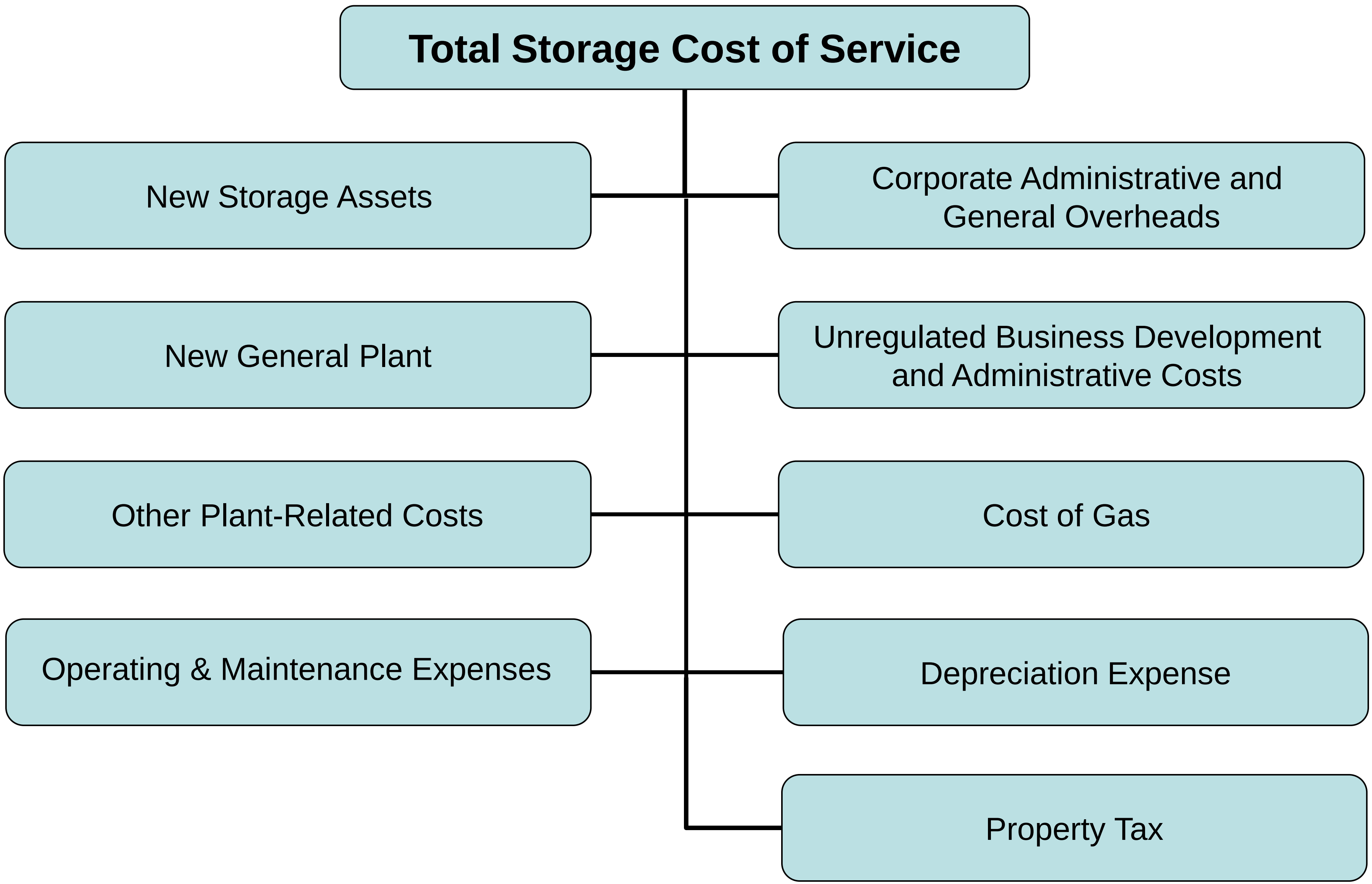
(2) Includes Transactional Services

(3) Regulated contract storage services for Union Gas Limited

(4) Regulated contract storage services for Union Gas Limited (0.11 Bcfd) and transmission deliverability services for Niagara Gas Transmission Ltd. (0.08 Bcfd)

(5) Unregulated storage operations started in May 2008

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Functional Process Flowchart



ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Timing of the Cost Allocation Process

Monthly/Annual	Periodic
•Storage Asset Additions and Retirements –Direct Assignments –Allocations	•New Depreciation Rates
•General Plant Additions and Retirements –Direct Assignments –Allocations	
•Operating and Maintenance Expenses –Direct Assignments –Allocations	
•Corporate Administrative and General Overheads –Loading Rates	
•Unregulated Business Development and Administrative Costs –Direct Assignment	
•Cost of Gas –Lost and Unaccounted for Gas –Allocations	
•Property Tax –Allocations	

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2007 Opening Balance	2007 Additions	2007 Provisions	2007 Ending Balance
Gross Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453				
Field Lines	455		$1,307,846		$1,307,846
Compressor Equipment	456		$7,043,209		$7,043,209
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals			$8,351,055		$8,351,055
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453				
Field Lines	455				
Compressor Equipment	456				
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals					
Net Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453				
Field Lines	455		$1,307,846		$1,307,846
Compressor Equipment	456		$7,043,209		$7,043,209
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals			$8,351,055		**$8,351,055**

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2008 Opening Balance	2008 Additions	2008 Provisions	2008 Ending Balance
Gross Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453		$3,929,319		$3,929,319
Field Lines	455	$1,307,846	$7,230,279		$8,538,125
Compressor Equipment	456	$7,043,209	$2,878,383		$9,921,592
Measuring & Regulating Equipment	457				
Work-In-Progress			$14,152,941		$14,152,941
Plant Not Classified					
Totals		$8,351,055	$28,190,922		$36,541,977
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453			($24,912)	($24,912)
Field Lines	455			($25,473)	($25,473)
Compressor Equipment	456			($53,053)	($53,053)
Measuring & Regulating Equipment	457				
Plant Not Classified					
Totals				($103,438)	($103,438)
Net Plant					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453		$3,929,319	($24,912)	$3,904,407
Field Lines	455	$1,307,846	$7,230,279	($25,473)	$8,512,652
Compressor Equipment	456	$7,043,209	$2,878,383	($53,053)	$9,868,539
Measuring & Regulating Equipment	457				
Work-In-Progress			$14,152,941		$14,152,941
Plant Not Classified		$8,351,055	$28,190,922	($103,438)	**$36,438,539**
Totals					

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2009 Opening Balance	2009 Additions	2009 Provisions	2009 Ending Balance
Gross Plant					
Land & Land Rights	450/451		$405,933		$405,933
Structures & Improvements	452				
Wells	453	$3,929,319	$3,608,934		$7,538,253
Field Lines	455	$8,538,125	$6,452,305		$14,990,430
Compressor Equipment	456	$9,921,592	$2,279,289		$12,200,881
Measuring & Regulating Equipment	457		$368,439		$368,439
Work-In-Progress		$14,152,941	($4,917,233)		$9,235,708
Plant Not Classified			$3,801,257		$3,801,257
Totals		$36,541,977	$11,998,924		$48,540,901
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453	($24,912)		($295,644)	($320,556)
Field Lines	455	($25,473)		($398,656)	($424,129)
Compressor Equipment	456	($53,053)		($287,662)	($340,715)
Measuring & Regulating Equipment	457			($13,264)	($13,264)
Plant Not Classified				($118,473)	($118,473)
Totals		($103,438)		($1,113,699)	($1,217,137)
Net Plant					
Land & Land Rights	450/451		$405,933		$405,933
Structures & Improvements	452				
Wells	453	$3,904,407	$3,608,934	($295,644)	$7,217,697
Field Lines	455	$8,512,652	$6,452,305	($398,656)	$14,566,301
Compressor Equipment	456	$9,868,539	$2,279,289	($287,662)	$11,860,166
Measuring & Regulating Equipment	457	$0	$368,439	($13,264)	$355,175
Work-In-Progress		$14,152,941	($4,917,233)		$9,235,708
Plant Not Classified			$3,801,257	($118,473)	$3,682,784
Totals		$36,438,539	$11,998,924	($1,113,699)	**$47,323,764**

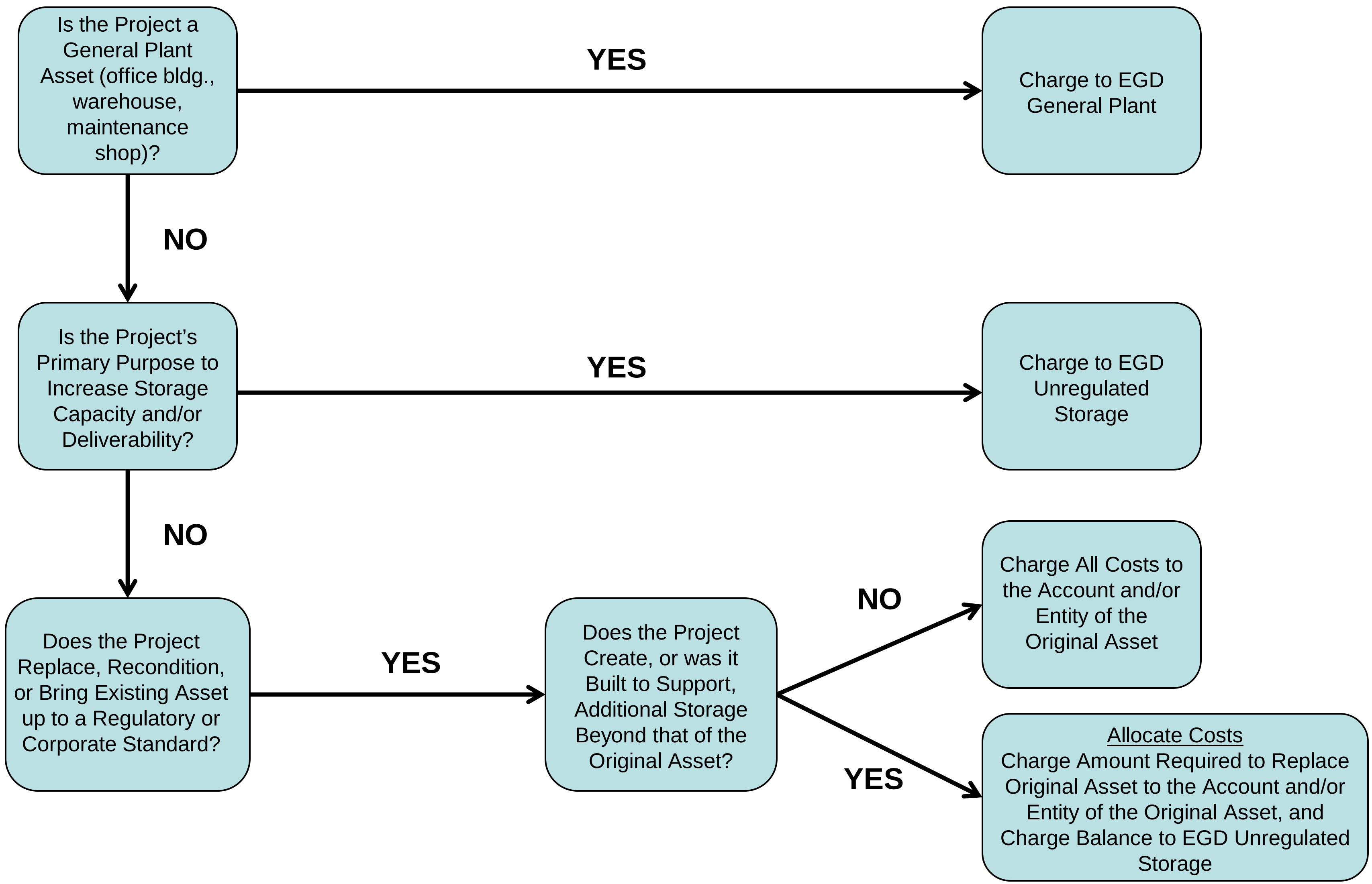
ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2010 Opening Balance	2010 Additions	2010 Provisions	2010 Ending Balance
Gross Plant					
Land & Land Rights	450/451	$405,933	$1,132,577	($411,207)	$1,127,303
Structures & Improvements	452				
Wells	453	$7,538,253	$3,071,174	$103,903	$10,713,330
Field Lines	455	$14,990,430	$89,821	$404,718	$15,484,969
Compressor Equipment	456	$12,200,881	$4,628,296	$4,072,396	$20,901,573
Measuring & Regulating Equipment	457	$368,439			$368,439
Work-In-Progress		$9,235,708	$8,574,447	($14,214,255)	$3,595,900
Plant Not Classified		$3,801,257		($3,801,257)	
Totals		$48,540,901	$17,496,315	($13,845,702)	$52,191,514
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453	($320,556)	($438,062)		($758,618)
Field Lines	455	($424,129)	($410,897)		($835,026)
Compressor Equipment	456	($340,715)	($485,789)		($826,504)
Measuring & Regulating Equipment	457	($13,264)	($13,264)		($26,528)
Plant Not Classified		($118,473)		$118,473	
Totals		($1,217,137)	($1,348,012)		($2,446,676)
Net Plant					
Land & Land Rights	450/451	$405,933	$1,132,577	($411,207)	$1,127,303
Structures & Improvements	452				
Wells	453	$7,217,697	$2,633,112	$103,903	$9,954,712
Field Lines	455	$14,566,301	($321,076)	$404,718	$14,649,943
Compressor Equipment	456	$11,860,166	$4,142,507	$4,072,396	$20,075,069
Measuring & Regulating Equipment	457	$355,175	($13,264)		$341,911
Work-In-Progress		$9,235,708	$8,574,447	($14,214,255)	$3,595,900
Plant Not Classified		$3,682,784		($3,682,784)	
Totals		$47,323,764	$16,148,303	($13,727,229)	**$49,744,838**

ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Gas Storage Assets
Net Plant - Year End Balances

Asset Description	Plant Account	2011 Opening Balance	2011 Additions	2011 Provisions	2011 Ending Balance
Gross Plant					
Land & Land Rights	450/451	$1,127,303			$1,127,303
Structures & Improvements	452				
Wells	453	$10,713,330		$129,191	$10,842,521
Field Lines	455	$15,484,969			$15,484,969
Compressor Equipment	456	$20,901,573	$13,275	$978,362	$21,893,210
Measuring & Regulating Equipment	457	$368,439			$368,439
Work-in-Progress		$3,595,900		($3,331,979)	$263,921
Plant Not Classified				$38,289,245	$38,289,245
Totals		$52,191,514	$13,275	$36,064,819	$88,269,608
Accumulated Depreciation Reserve					
Land & Land Rights	450/451				
Structures & Improvements	452				
Wells	453	($758,618)	($492,867)	($112)	($1,251,597)
Field Lines	455	($835,026)	($402,609)		($1,237,635)
Compressor Equipment	456	($826,504)	($465,330)	($40,190)	($1,332,024)
Measuring & Regulating Equipment	457	($26,528)	($13,264)		($39,792)
Plant Not Classified					
Totals		($2,446,676)	($1,374,070)	($40,302)	($3,861,048)
Net Plant					
Land & Land Rights	450/451	$1,127,303			$1,127,303
Structures & Improvements	452				
Wells	453	$9,954,712	($492,867)	$129,079	$9,590,924
Field Lines	455	$14,649,943	($402,609)		$14,247,334
Compressor Equipment	456	$20,075,069	($452,055)	$938,172	$20,561,186
Measuring & Regulating Equipment	457	$341,911	($13,264)		$328,647
Work-in-Progress		$3,595,900		($3,331,979)	$263,921
Plant Not Classified				$38,289,245	$38,289,245
Totals		$49,744,838	($1,360,795)	$36,024,517	**$84,408,560**

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Capital Project Assessment Process



ENBRIDGE GAS DISTRIBUTION INC.
Unregulated Storage Operation
2011 Operating and Maintenance Costs - Allocated

Expense Category	January	February	March	April	May	June	July	August	September	October	November	December	Annual
Administration	$6,394	$23,453	$41,846	$44,704	$41,278	$62,262	$72,798	$42,707	$52,862	$54,260	$57,640	$107,571	$607,775
Storage Operations	$15,574	$10,841	$11,369	$25,164	$16,909	$32,057	$23,492	$35,151	$23,608	$40,176	$46,564	$50,204	$331,109
Storage Maintenance	$30,981	$14,098	$6,420	$21,465	$21,030	$20,072	$6,428	$24,152	$33,442	$23,738	$55,684	$63,499	$321,009
Field Maintenance	$42,183	($1,993)	$4,062	$21,132	$7,284	($17,655)	$438	$5,150	$36,041	$15,268	$16,108	$13,656	$141,674
Total	$95,132	$46,399	$63,697	$112,465	$86,501	$96,736	$103,156	$107,160	$145,953	$133,442	$175,996	$234,930	**$1,401,567**

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: NOV-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.95	42.94%
Un-regulated	12.20	11.07%	2.59	57.06%
	110.2	100.00%	4.54	100.00%

COST CENTRE=25121 (STORAGE ADMINISTRATION)

	Actual	Applicable Share		Annual %	Annual $	Commodity %	Commodity $	Overhead Rate	
CONTROLLABLE COSTS									
60101 BASE PAY	150,645	95%	242,148	100%	242,148	0%	-	69.2%	
60109 TEMPORARY PAYRO	9,370	95%	15,061	100%	15,061	0%	-	69.2%	
60117 VACATION PAY	10,414	95%	16,740	100%	16,740	0%	-	69.2%	
60129 SCHEDULED OVERTIME	940	95%	1,511	100%	1,511	0%	-	69.2%	
60131 STATUTORY HOLID	0	95%	-	100%	-	0%	-	69.2%	
60133 SICK PAY	450	95%	723	100%	723	0%	-	69.2%	
60141 VACANCY CREDIT	0	95%	-	100%	-	0%	-	69.2%	
60145 OTHER SALARY EX	0	95%	-	100%	-	0%	-	69.2%	
TOTAL LABOUR	**171,819**		**276,183**		**276,183**		**0**		**30,576**
60401 EMPLOYEE TRAINI	12	95%	11	100%	11	0%	-		
60411 AWARDS AND ALLO	(446)	95%	(424)	100%	(424)	0%	-		
61105 COPIER AND OTHE	2,570	100%	2,570	100%	2,570	0%	-		
61116 COMPUTER SOFTWA	25,009	100%	25,009	100%	25,009	0%	-		
61511 PROFESSIONAL CO	0	100%	-	100%	-	0%	-		
61505 FILING FEES	725	100%	725	100%	725	0%	-		
61707 JANITORIAL SERVICES	9,496	100%	9,496	100%	9,496	0%	-		
61709 OFFICE REPAIRS	122	100%	122	100%	122	0%	-		
61715 POSTAGE COURIER	392	100%	392	100%	392	0%	-		
61717 REPRODUCTION SE	136	100%	136	100%	136	0%	-		
61910 SITE WORK	0	100%	-	100%	-	0%	-		
61999 OTHER OUTSIDE S	25,518	100%	25,518	100%	25,518	0%	-		
62301 VEHICLE / FLEET	10,193	100%	10,193	90%	9,174	10%	1,019		
70001 LAND LEASES	485,029	100%	485,029	100%	485,029	0%	-		
70409 OTHER TELECOM S	0	100%	-	100%	-	0%	-		
70501 AIRFARE	641	95%	609	100%	609	0%	-		
70503 GROUND TRANSPOR	1,278	95%	1,214	100%	1,214	0%	-		
70505 ACCOMMODATION	1,942	95%	1,845	100%	1,845	0%	-		
70507 MEALS AND ENTER	2,933	95%	2,786	100%	2,786	0%	-		
70509 OTHER TRAVEL EX	328	95%	312	100%	312	0%	-		
70511 CONFERENCE AND	421	95%	400	100%	400	0%	-		
70701 PROPERTY TAXES	128,706	100%	128,706	100%	128,706	0%	-		
70809 TRADE AND CIVIC	1,797	100%	1,797	100%	1,797	0%	-		
NON-LABOUR COST CENTRE COSTS	**696,802**		**696,446**		**695,427**		**1,019**		**77,571**
INTERNAL COST RECOVERIES									
79966 VARIABLE INTERN	(5,200)	100%	(5,200)	100%	(5,200)	0%	-		
79967 OTHER RECOVERIE CAPITAL	0	100%	0	100%	0	0%	-		
TOTAL COST RECOVERIES	**(5,200)**		**(5,200)**		**(5,200)**		**-**		**(576)**
TOTAL NET COST CENTRE COSTS	**863,420**		**967,429**		**966,410**		**1,019**		
			CHARGES TO UN-REGULATED		106,989		582		
							107,571		

OPERATING COST REPORT - DETAIL CADSEP

CADDEC

Period: NOV-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.95	42.94%
Un-regulated	12.20	11.07%	2.59	57.06%
	110.2	100.00%	4.54	100.00%

COST CENTRE=25122 (STORAGE OPERATIONS)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $	Overhead Factoı
CONTROLLABLE COSTS							
60101 BASE PAY	14,057	100%	100%	23,204	0%	0	65.1%
60105 HOURLY PAYROLL	70,747	100%	100%	116,786	0%	0	65.1%
60117 VACATION PAY	5,570	100%	100%	9,195	0%	0	65.1%
60129 SCHEDULED OVERT	50,903	100%	80%	67,222	20%	16,806	65.1%
60131 STATUTORY HOLID	0	100%	100%	0	0%	0	65.1%
60133 SICK PAY	6,350	100%	100%	10,482	0%	0	65.1%
60145 OTHER SALARY EX	0	100%	100%	0	0%	0	65.1%
TOTAL LABOUR	**147,627**			**226,889**		**16,806**	
61009 SAFETY RELATED	4,995	100%	100%	4,995	0%	0	
61299 OTHER MATERIALS	7,504	100%	40%	3,002	60%	4,503	
61601 CONTRACT SERVIC	0	100%	100%	0	0%	0	
61805 ENVIRONMENTAL C	2,427	100%	100%	2,427	0%	0	
61999 OTHER OUTSIDE S	30,710	100%	40%	12,284	60%	18,426	
NON-LABOUR COST CENTRE COSTS	**45,635**			**22,707**		**22,929**	
INTERNAL COST RECOVERIES							
79966 VARIABLE INTERN	(906)	100%	100%	(906)	0%	0	100%
79967 OTHER RECOVERIE CAPITAL		100%	100%	0	0%	0	100%
TOTAL COST RECOVERIES	**(906)**			**(906)**		**0**	
TOTAL NET COST CENTRE COSTS	**192,356**			**248,690**		**39,734**	
			CHARGES TO UN-REGULATED	**27,532**		**22,672**	
						50,204	

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: NOV-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.95	42.94%
Un-regulated	12.20	11.07%	2.59	57.06%
	110.2	100.00%	4.54	100.00%

COST CENTRE=25123 (STORAGE MAINTENANCE)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $	Overhead Factor
CONTROLLABLE COSTS							
60101 BASE PAY	64,726	100%	100%	110,046	0%	0	70.0%
60105 HOURLY PAYROLL	0	100%	100%	0	0%	0	70.0%
60117 VACATION PAY	1,692	100%	100%	2,877	0%	0	70.0%
60129 SCHEDULED OVERT	8,419	100%	40%	5,726	60%	8,588	70.0%
60131 STATUTORY HOLID	0	100%	100%	0	0%	0	70.0%
60133 SICK PAY	9,839	100%	100%	16,728	0%	0	70.0%
60145 OTHER SALARY EX	0	100%	100%	0	0%	0	70.0%
TOTAL LABOUR	**84,676**			**135,376**		**8,588**	
60401 EMPLOYEE TRAINI	10,862	100%	40%	4,345	60%	6,517	
61299 OTHER MATERIALS	65,786	100%	40%	26,314	60%	39,472	
61601 CONTRACT SERVIC	40,964	100%	40%	16,385	60%	24,578	
NON-LABOUR COST CENTRE COSTS	**117,612**			**47,045**		**70,567**	
INTERNAL COST RECOVERIES							
79951 CAPITAL PROJECT	(12,022)	100%	100%	(12,022)	0%	0	100%
79966 VARIABLE INTERN	(4,800)	100%	100%	(4,800)	0%	0	100%
79967 OTHER RECOVERIE CAPITAL		100%	100%	0	0%	0	100%
TOTAL COST RECOVERIES	**(16,822)**			**(16,822)**		**0**	
TOTAL NET COST CENTRE COSTS	**185,466**			**165,599**		**79,155**	
CHARGES TO UN-REGULATED				**18,333**		**45,166**	
						63,499	

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: NOV-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.95	42.94%
Un-regulated	12.20	11.07%	2.59	57.06%
	110.20	100.00%	4.54	100.00%

COST CENTRE=25124 (FIELD MAINTENANCE)

	Actual	Applicable Share	Annual %	Annual $	Commodity %	Commodity $
CONTROLLABLE COSTS						
61299 OTHER MATERIALS	0	100%	100%	0	0%	0
61511 PROFESSIONAL CO	2,060	100%	100%	2,060	0%	0
61601 CONTRACT SERVIC	112,493	100%	100%	112,493	0%	0
61805 ENVIRONMENTAL C	8,803	100%	100%	8,803	0%	0
DIRECT COST CENTRE COSTS	**123,356**			**123,356**		**0**
TOTAL NET COST CENTRE COSTS	**123,356**			**123,356**		**0**
CHARGES TO UN-REGULATED				**13,656**		**0**
						13,656

ORACLE Applications

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: DEC-11 Currency: CAD
Submitted: 10-JAN-12 10:46:28

LOB=25104 (ENBRIDGE GAS DISTRIBUTION - UNREGULATED), COST CENTRE=25371 (UNREGULATED STORAGE)

	Current Month			Year To Date			Full Year
	Actual	Budget	Variance	Actual	Budget	Variance	Budget
CONTROLLABLE COSTS							
60101 BASE PAY	38,151.00	31,770.00	(6,381.00)	563,996.00	379,324.00	(184,672.00)	379,324.00
60109 TEMPORARY PAYRO	10,080.00	0.00	(10,080.00)	121,480.00	0.00	(121,480.00)	0.00
60117 VACATION PAY	9,328.00	0.00	(9,328.00)	45,571.00	0.00	(45,571.00)	0.00
60131 STATUTORY HOLID	4,261.00	0.00	(4,261.00)	27,143.00	0.00	(27,143.00)	0.00
60133 SICK PAY	0.00	0.00	0.00	3,139.00	0.00	(3,139.00)	0.00
60401 EMPLOYEE TRAINI	300.00	0.00	(300.00)	375.00	0.00	(375.00)	0.00
60412 EMPLOYEE RECOGN	0.00	0.00	0.00	179.00	0.00	(179.00)	0.00
61105 COPIER AND OTHE	0.00	50.00	50.00	285.00	600.00	315.00	600.00
61116 COMPUTER SOFTWA	0.00	3,000.00	3,000.00	0.00	36,000.00	36,000.00	36,000.00
61299 OTHER MATERIALS	0.00	0.00	0.00	496.00	0.00	(496.00)	0.00
61503 LEGAL FEES	149.00	0.00	(149.00)	1,885.00	0.00	(1,885.00)	0.00
61511 PROFESSIONAL CO	3,452.00	25,000.00	21,548.00	17,717.00	300,000.00	282,283.00	300,000.00
61601 CONTRACT SERVIC	(6,433.00)	21,550.00	27,983.00	40,692.00	258,600.00	217,908.00	258,600.00
61715 POSTAGE COURIER	0.00	25.00	25.00	278.00	300.00	22.00	300.00
61717 REPRODUCTION SE	0.00	0.00	0.00	1,540.00	2,500.00	960.00	2,500.00
61999 OTHER OUTSIDE S	10,000.00	280,000.00	270,000.00	120,000.00	1,360,000.00	1,240,000.00	1,360,000.00
70407 IT TELECOM SERV	0.00	0.00	0.00	88.00	0.00	(88.00)	0.00
70501 AIRFARE	(12,518.00)	1,250.00	13,768.00	8,066.00	15,000.00	6,934.00	15,000.00
70503 GROUND TRANSPOR	(4,242.00)	375.00	4,617.00	6,230.00	4,500.00	(1,730.00)	4,500.00
70505 ACCOMMODATION	4,274.00	1,000.00	(3,274.00)	10,258.00	12,000.00	1,742.00	12,000.00
70507 MEALS AND ENTER	(1,070.00)	500.00	1,570.00	2,261.00	6,000.00	3,739.00	6,000.00
70509 OTHER TRAVEL EX	0.00	200.00	200.00	0.00	2,400.00	2,400.00	2,400.00
70511 CONFERENCE AND	0.00	0.00	0.00	2,279.00	10,100.00	7,821.00	10,100.00
70809 TRADE AND CIVIC	0.00	0.00	0.00	220.00	0.00	(220.00)	0.00
70899 OTHER OPERATING	314,888.00	89,137.00	(225,751.00)	1,401,631.00	1,069,645.00	(331,986.00)	1,069,645.00
DIRECT COST CENTRE COSTS	370,620.00	453,857.00	83,238.00	2,375,809.00	3,456,969.00	1,081,160.00	3,456,969.00
ACCOUNTABLE COSTS							
74002 FIXED INTERNAL	11,561.00	19,127.00	7,566.00	138,732.00	229,522.00	90,790.00	229,522.00
74007 GENERAL EXPENSE	3,613.00	0.00	(3,613.00)	43,356.00	0.00	(43,356.00)	0.00
TOTAL ACCOUNTABLE COSTS	15,174.00	19,127.00	3,953.00	182,088.00	229,522.00	47,434.00	229,522.00
GROSS OPERATING COSTS	385,794.00	472,984.00	87,190.00	2,557,897.00	3,686,491.00	1,128,594.00	3,686,491.00
INTERNAL COST RECOVERIES							
79951 CAPITAL PROJECT	(46,145.00)	0.00	46,145.00	(552,302.00)	0.00	552,302.00	0.00
79966 VARIABLE INTERN	0.00	(2,490.00)	(2,490.00)	(59,114.00)	(29,880.00)	29,234.00	(29,880.00)
TOTAL INTERNAL COST RECOVERIES	(46,145.00)	(2,490.00)	43,655.00	(611,416.00)	(29,880.00)	581,536.00	(29,880.00)
TOTAL NET OPERATING COSTS	339,649.00	470,494.00	130,845.00	1,946,481.00	3,656,611.00	1,710,130.00	3,656,611.00

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Deliverability Bcf	Deliverability % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.94	82.91%	11.82	95.51%
Un-regulated	12.20	11.07%	0.40	17.09%	0.56	4.49%
	110.20	100.00%	2.34	100.00%	12.38	100.00%

COST CENTRE=25121 (STORAGE ADMINISTRATION)

					Split of the Balance			Resulting Allocations: Capacity		Deliverability		Commodity	
	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Cap	Deliv	%	$s	%	$s	%	$s
CONTROLLABLE COSTS													
60101 BASE PAY	137,178	100%	69.2%	232,107	5%	75%	25%	71%	165,376	24%	55,125	5%	11,605
60109 TEMPORARY PAYRO	9,767	100%	69.2%	16,526	5%	75%	25%	71%	11,775	24%	3,925	5%	826
60117 VACATION PAY	16,068	100%	69.2%	27,187	5%	75%	25%	71%	19,371	24%	6,457	5%	1,359
60129 SCHEDULED OVERTIME	2,860	100%	69.2%	4,839	5%	75%	25%	71%	3,448	24%	1,149	5%	242
60131 STATUTORY HOLID	7,331	100%	69.2%	12,404	5%	75%	25%	71%	8,838	24%	2,946	5%	620
60133 SICK PAY	0	100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
60141 VACANCY CREDIT	0	100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
60145 OTHER SALARY EX	0	100%	69.2%	-	5%	75%	25%	71%	-	24%	-	5%	-
TOTAL LABOUR	173,204			293,063									
60401 EMPLOYEE TRAINI	1,275	100%		1,275	5%	75%	25%	71%	908	24%	303	5%	64
60403 EXECUTIVE DEVELOPMENT	(1,275)	100%		(1,275)	5%	75%	25%	71%	(908)	24%	(303)	5%	(64)
60405 RECRUITMENT ADV	(1,155)	100%		(1,155)	5%	75%	25%	71%	(823)	24%	(274)	5%	(58)
60411 AWARDS AND ALLO	11	100%		11	5%	75%	25%	71%	8	24%	3	5%	1
61009 SAFETY RELATED	(942)	100%		(942)	5%	75%	25%	71%	(671)	24%	(224)	5%	(47)
61105 COPIER AND OTHE	1,477	100%		1,477	5%	75%	25%	71%	1,052	24%	351	5%	74
61116 COMPUTER SOFTWA	25,392	100%		25,392	0%	75%	25%	75%	19,044	25%	6,348	0%	-
61511 PROFESSIONAL CO	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
61601 CONTRACT SERVICES	(8,925)	100%		(8,925)	0%	75%	25%	75%	(6,694)	25%	(2,231)	0%	-
61707 JANITORIAL SERVICES	4,854	100%		4,854	0%	75%	25%	75%	3,641	25%	1,214	0%	-
61709 OFFICE REPAIRS	252	100%		252	0%	75%	25%	75%	189	25%	63	0%	-
61715 POSTAGE COURIER	2,237	100%		2,237	0%	75%	25%	75%	1,678	25%	559	0%	-
61717 REPRODUCTION SE	1,952	100%		1,952	0%	75%	25%	75%	1,464	25%	488	0%	-
61910 SITE WORK	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
61999 OTHER OUTSIDE S	23,305	100%		23,305	5%	75%	25%	71%	16,605	24%	5,535	5%	1,165
62301 VEHICLE / FLEET	7,726	100%		7,726	10%	75%	25%	68%	5,215	23%	1,738	10%	773
70001 LAND LEASES	14,558	100%		14,558	0%	90%	10%	90%	13,102	10%	1,456	0%	-
70409 OTHER TELECOM S	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70501 AIRFARE	1,301	100%		1,301	5%	75%	25%	71%	927	24%	309	5%	65
70503 GROUND TRANSPOR	1,613	100%		1,613	5%	75%	25%	71%	1,149	24%	383	5%	81
70505 ACCOMMODATION	1,134	100%		1,134	5%	75%	25%	71%	808	24%	269	5%	57
70507 MEALS AND ENTER	2,597	100%		2,597	5%	75%	25%	71%	1,850	24%	617	5%	130
70509 OTHER TRAVEL EX	38	100%		38	5%	75%	25%	71%	27	24%	9	5%	2
70511 CONFERENCE AND	3,377	100%		3,377	0%	75%	25%	75%	2,533	25%	844	0%	-
70701 PROPERTY TAXES	128,706	100%		128,706	0%	40%	60%	40%	51,482	60%	77,224	0%	-
70707 VEHICLE LICENSI	(11)	100%		(11)	0%	75%	25%	75%	(8)	25%	(3)	0%	-
70801 CORPORATE DONAT	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70807 SPONSORSHIPS	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	-
70809 TRADE AND CIVIC	747	100%		747	0%	75%	25%	75%	560	25%	187	0%	-
NON-LABOUR COST CENTRE COSTS	210,244			210,244									
INTERNAL COST RECOVERIES													
79966 VARIABLE INTERN	(1,000)	100%		(1,000)	0%	75%	25%	75%	(750)	25%	(250)	0%	-
79967 OTHER RECOVERIE CAPITAL	(9,137)	100%		(9,137)	0%	75%	25%	75%	(6,853)	25%	(2,284)	0%	-
TOTAL COST RECOVERIES	(10,137)			(10,137)									
TOTAL NET COST CENTRE COSTS	373,311			493,170					314,343		161,932		16,895
									63.7%		32.8%		3.4%
									34,800		27,681		759
										Allocation to Unregulated Storage			63,240

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Deliverability Bcf	Deliverability % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.94	82.91%	11.82	95.51%
Un-regulated	12.20	11.07%	0.40	17.09%	0.56	4.49%
	110.20	100.00%	2.34	100.00%	12.38	100.00%

COST CENTRE=25122 (STORAGE OPERATIONS)

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Split of the Balance Cap	Split of the Balance Deliv	Resulting Allocations Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
CONTROLLABLE COSTS													
60101 BASE PAY	11,566	100%	65.1%	19,093	0%	75%	25%	75%	14,319	25%	4,773	0%	0
60105 HOURLY PAYROLL	81,044	100%	65.1%	133,783	0%	75%	25%	75%	100,337	25%	33,446	0%	0
60117 VACATION PAY	3,155	100%	65.1%	5,208	0%	75%	25%	75%	3,906	25%	1,302	0%	0
60129 SCHEDULED OVERT	27,028	100%	65.1%	44,616	10%	75%	25%	68%	30,116	23%	10,039	10%	4,462
60131 STATUTORY HOLID	4,613	100%	65.1%	7,615	0%	75%	25%	75%	5,711	25%	1,904	0%	0
60133 SICK PAY	0	100%	65.1%	-	0%	75%	25%	75%	-	25%	-	0%	0
60145 OTHER SALARY EX	0	100%	65.1%	-	0%	75%	25%	75%	-	25%	-	0%	0
TOTAL LABOUR	127,406			210,315									
61009 SAFETY RELATED	1,929	100%		1,929	0%	75%	25%	75%	1,447	25%	482	0%	0
61299 OTHER MATERIALS	38,603	100%		38,603	60%	40%	60%	16%	6,176	24%	9,265	60%	23,162
61601 CONTRACT SERVIC	31,071	100%		31,071	0%	75%	25%	75%	23,303	25%	7,768	0%	0
61805 ENVIRONMENTAL C	646	100%		646	0%	40%	60%	40%	258	60%	388	0%	0
61999 OTHER OUTSIDE S	43,161	100%		43,161	60%	40%	60%	16%	6,906	24%	10,359	60%	25,897
NON-LABOUR COST CENTRE COSTS	115,410			115,410									
INTERNAL COST RECOVERIES				-									
79966 VARIABLE INTERN	(78,009)	100%		(78,009)	0%	75%	25%	75%	(58,507)	25%	(19,502)	0%	0
79967 OTHER RECOVERIE CAPITAL	0	100%		-	0%	75%	25%	75%	-	25%	-	0%	0
TOTAL COST RECOVERIES	(78,009)			(78,009)									
TOTAL NET COST CENTRE COSTS	164,807			247,716					133,974		60,222		53,520
									54.1%		24.3%		21.6%
									14,832		10,294		2,404
										Allocation to Unregulated Storage			27,530

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

	Annual Capacity Bcf	Annual Capacity % of Total	Deliverability Bcf	Deliverability % of Total	Commodity Bcf	Commodity % of Total
Regulated	98.00	88.93%	1.94	82.91%	11.82	95.51%
Un-regulated	12.20	11.07%	0.40	17.09%	0.56	4.49%
	110.20	100.00%	2.34	100.00%	12.38	100.00%

COST CENTRE=25123 (STORAGE MAINTENANCE)

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Split of the Balance Cap	Split of the Balance Deliv	Resulting Allocations: Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
CONTROLLABLE COSTS													
60101 BASE PAY	56,108	100%	70.0%	95,394	0%	75%	25%	75.0%	71,545	25%	23,848	0%	-
60105 HOURLY PAYROLL	0	100%	70.0%	-	0%	75%	25%	75.0%	-	25%	-	0%	-
60117 VACATION PAY	6,436	100%	70.0%	10,942	0%	75%	25%	75.0%	8,207	25%	2,736	0%	-
60129 SCHEDULED OVERT	692	100%	70.0%	1,177	60%	75%	25%	30.0%	353	10%	118	60%	706
60131 STATUTORY HOLID	2,597	100%	70.0%	4,415	0%	75%	25%	75.0%	3,312	25%	1,104	0%	-
60133 SICK PAY	0	100%	70.0%	-	0%	75%	25%	75.0%	-	25%	-	0%	-
60145 OTHER SALARY EX	0	100%	70.0%	-	0%	75%	25%	75.0%	-	25%	-	0%	-
TOTAL LABOUR	65,833			111,928									
60401 EMPLOYEE TRAINI	8,742	100%		8,742	60%	75%	25%	30.0%	2,623	10%	874	60%	5,245
61299 OTHER MATERIALS	110,429	100%		110,429	60%	40%	60%	16.0%	17,669	24%	26,503	60%	66,257
61601 CONTRACT SERVIC	70,091	100%		70,091	60%	40%	60%	16.0%	11,215	24%	16,822	60%	42,055
NON-LABOUR COST CENTRE COSTS	189,262			189,262									
INTERNAL COST RECOVERIES													
79951 CAPITAL PROJECT	(9,870)	100%		(9,870)	0%	75%	25%	75.0%	(7,403)	25%	(2,468)	0%	-
79966 VARIABLE INTERN	78,672	100%		78,672	0%	75%	25%	75.0%	59,004	25%	19,668	0%	-
79967 OTHER RECOVERIE CAPITAL	0	100%		-	0%	75%	25%	75.0%	-	25%	-	0%	-
TOTAL COST RECOVERIES	68,802			68,802									
TOTAL NET COST CENTRE COSTS	323,897			369,992					166,524		89,205		114,263
									45.0%		24.1%		30.9%
									18,435		15,249		5,132
Allocation to Unregulated Storage													38,816

OPERATING COST REPORT - DETAIL CADSEP

CADDEC
Period: AUG-11 Currency: CAD

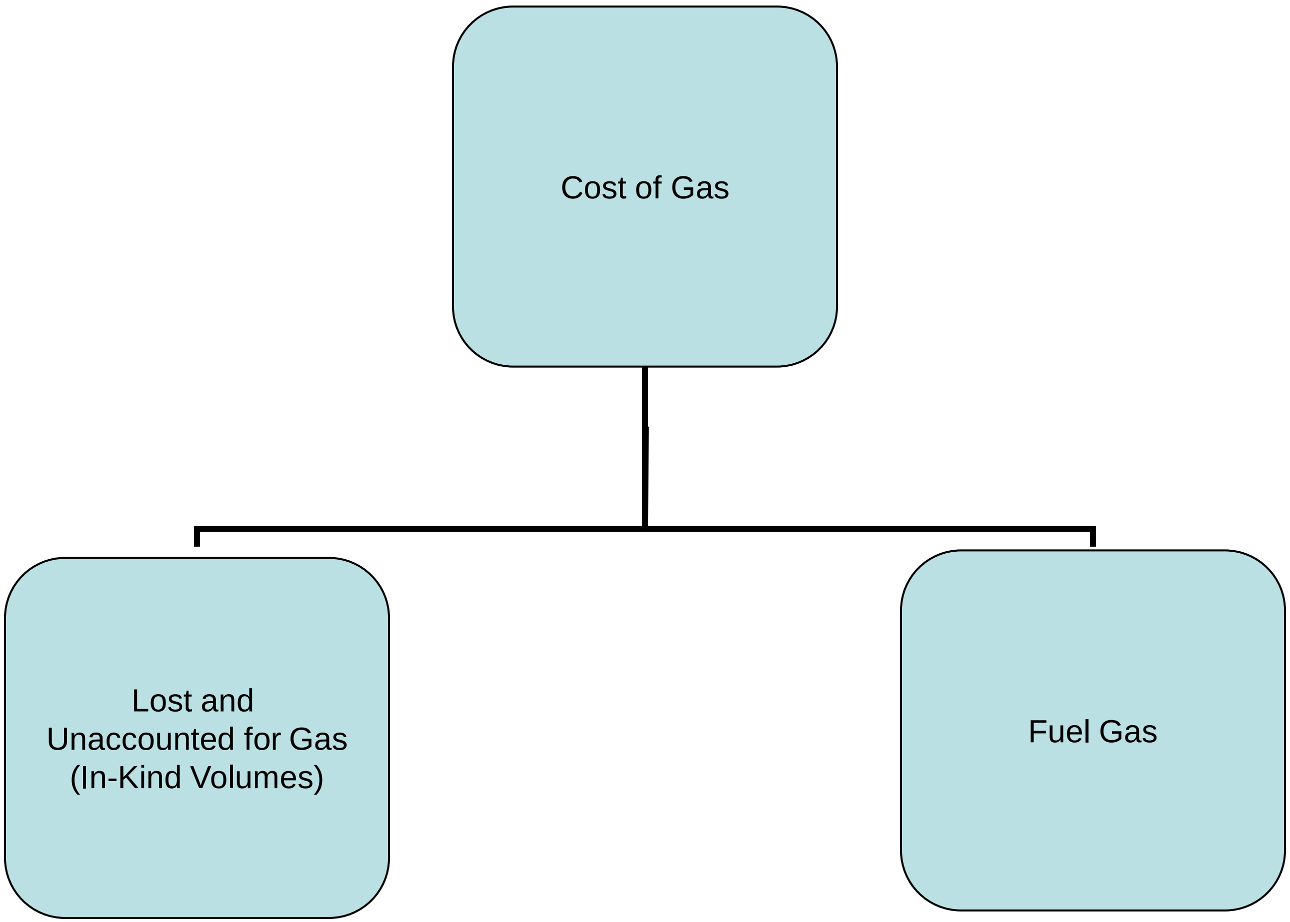
	Annual Capacity		Deliverability		Commodity	
	Bcf	% of Total	Bcf	% of Total	Bcf	% of Total
Regulated	98.00	**88.93%**	1.94	**82.91%**	11.82	**95.51%**
Un-regulated	12.20	**11.07%**	0.40	**17.09%**	0.56	**4.49%**
	110.20	100.00%	2.34	100.0%	12.38	100.00%

COST CENTRE=25124 (FIELD MAINTENANCE)

	Actual	Applicable Share	Overhead Factor	Allocable Amount	Comm.	Split of the Balance Cap	Split of the Balance Deliv	Capacity %	Capacity $s	Deliverability %	Deliverability $s	Commodity %	Commodity $s
CONTROLLABLE COSTS													
61299 OTHER MATERIALS	8,859	100%	0	8,859	0%	40%	60%	40.0%	3,544	60.0%	5,315	0.0%	-
61511 PROFESSIONAL CO	11,772	100%	0	11,772	0%	90%	10%	90.0%	10,595	10.0%	1,177	0.0%	-
61601 CONTRACT SERVIC	304,920	100%	0	304,920	0%	40%	60%	40.0%	121,968	60.0%	182,952	0.0%	-
61805 ENVIRONMENTAL C	0	100%	0	-	0%	40%	60%	40.0%	-	60.0%	-	0.0%	-
DIRECT COST CENTRE COSTS	**325,551**			**325,551**									
TOTAL NET COST CENTRE COSTS	**325,551**			**325,551**					**136,106**		**189,445**		**0**
									41.8%		58.2%		0.0%
									15,068		32,384		-
										Allocation to Unregulated Storage			**47,452**

Schedule 8

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Cost of Gas Components

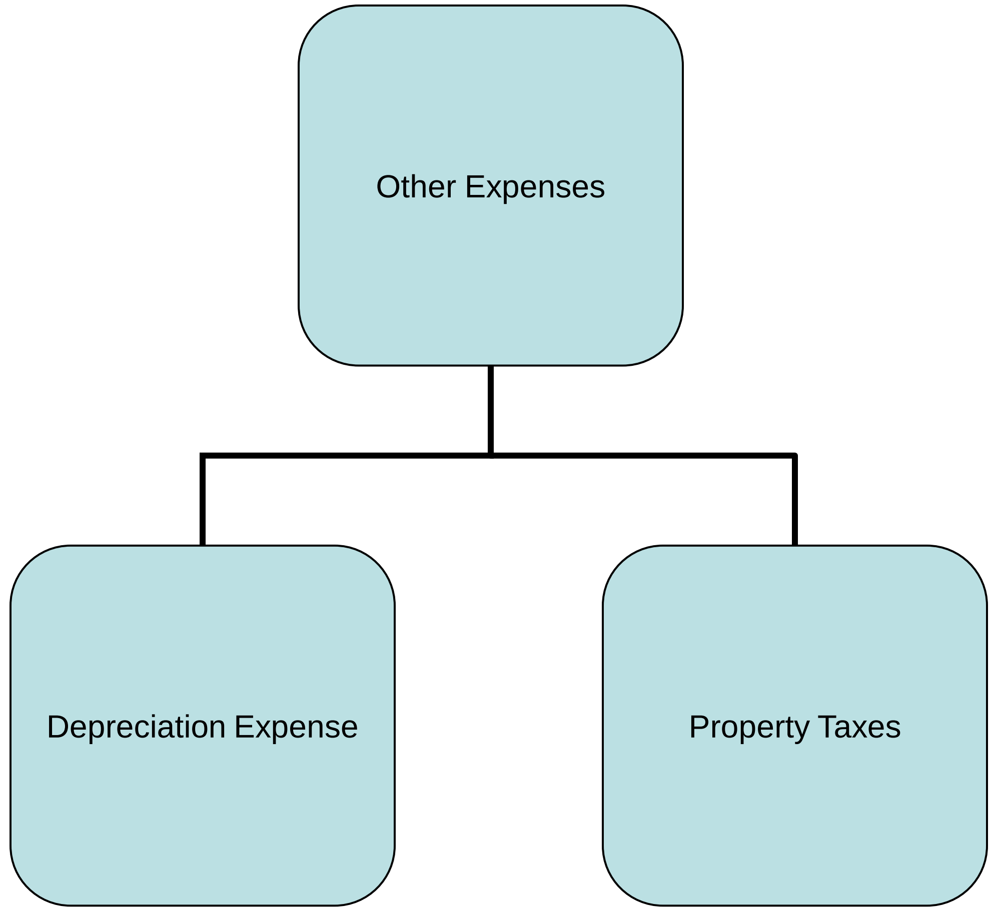


- Actual storage capacity and activity
- LUF replacement factor

- Actual monthly storage activity
- Previous October QRAM reference price of gas

Schedule 9

ENBRIDGE GAS DISTRIBUTION INC.
Allocation of Regulated and Unregulated Storage Costs
Other Expenses



- Depreciation rates for Unregulated storage assets
- Actual property tax for storage assets – allocated between regulated and unregulated storage operations based on the annual storage capacity and deliverability of each storage operation