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

Lorraine Chiasson
Regulatory Coordinator
phone: (416) 495-5499
fax: (416) 495-6072
Email: egdregulatoryaffairs@enbridge.com

May 20, 2015

VIA EMAIL, RESS, and COURIER

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

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("the Company")
2014 Earnings Sharing Mechanism and Other Deferral And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2015-0122

Enclosed is an Application and supporting evidence by Enbridge Gas Distribution Inc. for an order approving the clearance or disposition of amounts recorded within its 2014 Earnings Sharing Mechanism Deferral Account and within certain other deferral or variance accounts.

This information is being filed through the Board's RESS system today.

Enbridge Gas Distribution will provide the Application materials on the Company's website at www.enbridgegas.com/ratecase.

Yours truly,

(Original Signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2012-0276 (via email)

EXHIBIT LIST

A – ADMINISTRATIVE

Exhibit	Tab	Schedule	Contents	Witness(es)
A	1	1	Exhibit List	K. Culbert
	2	1	Application	K. Culbert
	3	1	Overview and Approvals Requested	K. Culbert R. Small
	4	1	Draft Issues List	K. Culbert
	5	1	Curriculum Vitae	K. Culbert

B – 2014 ACTUAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	ESM Calculations	R. Small
		2	ESM Calculations and Required Rate of Return 2014 Actuals	R. Small
		3	2014 Utility Earnings – Contributors to Utility Earnings and earnings Sharing Amounts	R. Small
		4	Utility Earnings – Contributions to Utility Earnings and Earnings Sharing Amounts	R. Small
	2	1	Ontario Utility Rate Base – Comparison of 2014 Actuals to 2014 Board Approved	R. Small
		2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2014 Actuals	R. Small
		3	Working Capital – 2014 Actuals	R. Small

EXHIBIT LIST

B – 2014 ACTUAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	2	4	Comparison of Utility Capital Expenditures 2014 Actuals and 2014 Board Approved	L. Au T. Knight
	3	1	Utility Operating Revenue 2014 Actuals	R. Small
		2	Comparison of Gas Sales and Transportation Volume by Rate Class 2014 Actuals to 2014 Board Approved	L. Stickles
		3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2014 Actuals to 2014 Board Approved	L. Stickles
		4	Customers Meters, Volumes and Revenues by Rate Class 2014 Actuals	L. Stickles
		5	Other Operating Revenue	R. Small L. Stickles
	4	1	Operating Cost 2014 Actuals	R. Small
		2	Operating and Maintenance Expense by Department Ending December 2014	A. Patel L. Stickles
	5	1	Required Rate of Return 2014 Actuals	R. Small
		2	Utility Income 2014 Actuals	R. Small
		3	Cost of Capital 2014 Actuals	R. Small

EXHIBIT LIST

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, 2015	R. Small
		2	2014 Design Day Criteria Transportation Cost Deferral Account & Unabsorbed Demand Charge Deferral Account explanation	J. LeBlanc D. Small
		3	2014 Storage & Transportation Deferral Account and 2014 Transactional Services Deferral Account	J. LeBlanc D. Small
		4	2014 Unaccounted For Variance Account explanation	M. Suarez
		5	2014 Average Use True Up Variance Account explanation	M. Suarez
		6	2014 Post retirement True Up Variance Account explanation	J. Barradas J. Shem
		7	2014 Gas Distribution Access Rule Impact Deferral Account	D. McIlwraith R. Small
		8	2014 Deferred Rebate Account	R. Small
		9	2015 Transition Impact of Accounting Changes Deferral Account	R. Small
		10	2014 Customer Care CIS Rate Smoothing Deferral Account	D. McIlwraith R. Small
		11	Customer Final Bill Deferral Account	D. McIlwraith R. Small

EXHIBIT LIST

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	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 – REPORTING AND REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Status Updates	K. Culbert
		2	Status of GTA Project	S. Dodd O. Schneider
		3	Status of WAMS Project	W. Akkermans B. Misra
		4	Status of System Integrity Program	D. Broude D. Lapp
		5	Status of Benchmarking Study	K. Culbert I. Macpherson M. Suarez
		6	Status of Asset Management Planning Process	T. MacLean
	2	1	Productivity Initiatives Summary	I. Macpherson M. Suarez
	3	1	April 1, 2015 Stakeholder Day Presentation	K. Culbert

EXHIBIT LIST

D – REPORTING AND REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	4	1	2015 Gas Supply Memorandum	D. Small A. Welburn
	5	1	2014 RRR filings re. Service Quality Indicators	K. Lakatos-Hayward L. Parrington
	6	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2014	J. Barradas
		2	Enbridge Gas Distribution Inc. Management's Discussion & Analysis – December 31, 2014	J. Barradas

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

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

A P P L I C A T I O N

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

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

3. Within the Decision with Reasons in the EB-2012-0459 proceeding, the Board established a Custom IR framework to set Enbridge's rates over the period from 2014 to 2018. Among other things, this includes an Earnings Sharing Mechanism ("ESM") under which Enbridge is to share earnings above the Board-approved Return on Equity ("ROE") with ratepayers on a 50/50 basis. The Custom IR framework includes a number of Deferral and Variance Accounts to be maintained or created during the Custom IR term.

4. Under the Custom IR framework, after the release of its Audited Financial Statements for the prior year Enbridge is required to file an Application setting out the

ESM calculation for that year. Within the Application, Enbridge is to set out its proposal for the clearance of amounts recorded in the Earnings Sharing Mechanism Deferral Account ("ESMDA") and other Deferral and Variance Accounts.

5. Pursuant to the EB-2012-0459 Decision with Reasons, Enbridge is also required to annually report upon the status of a number of initiatives and activities as part of the ESM Application.

6. In this Application, Enbridge seeks approval to clear the balance of the 2014 ESMDA, as well as the balances within certain of its 2014 Deferral and Variance accounts and the 2015 TIACDA and CFBDA, and also seeks approval to carry forward the balances in certain of these accounts for review and approval in a later proceeding. The relevant balances are included within the table at Appendix A to this Application.

7. Enbridge therefore applies to the Board for such final, interim or other Orders as may be necessary or appropriate for the clearance or disposition of the 2014 ESMDA and the other Deferral and Variance accounts listed in Appendix A to this Application. Enbridge proposes to clear the balances in these accounts in conjunction with the October 1, 2015 QRAM Application.

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

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

The Applicant:

Mr. Andrew Mandyam
Director, Regulatory Affairs and Financial Performance
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. David Stevens
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:	416-865-7783
Fax:	416-863-1515
Email:	dstevens@airdberlis.com

DATED: May 20, 2015 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

(Original Signed)

Per: ____________________________

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

			Col. 1	Col. 2	Col. 3	Col. 4	
			Actual at April 30, 2015		Forecast for clearance at October 1, 2015		
Line No.	Account Description	Account Acronym	Principal	Interest	Principal	Interest	
			($000's)	($000's)	($000's)	($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2014 DSMVA	352.5	1.6	-	-	[1]
2.	Deferred Rebate Account	2014 DRA	(3,167.6)	(10.7)	(3,167.6)	(25.2)	[2]
3.	Gas Distribution Access Rule Impact D/A	2014 GDARIDA	-	-	152.7	-	[3]
4.	Average Use True-Up V/A	2014 AUTUVA	(4,894.0)	(22.5)	(4,894.0)	(45.0)	[4]
5.	Earnings Sharing Mechanism Deferral Account	2014 ESMDA	(12,650.0)	(55.7)	(12,650.0)	(113.7)	[5]
6.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	34.0	-	52.0	[6]
7.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	122.1	-	150.6	[6]
8.	Transition Impact of Accounting Changes D/A	2015 TIACDA	79,844.4	-	4,435.8	-	[7]
9.	Post-Retirement True-Up V/A	2014 PTUVA	(6,220.6)	(28.6)	(5,000.0)	(45.9)	[8]
10.	Credit Final Bill D/A	2015 CFBDA	-	-	(5,517.6)	(20.4)	[9]
11.	Manufactured Gas Plant D/A	2015 MGPDA	426.4	30.0	-	-	[10]
12.	Constant Dollar Net Salvage Adjustment D/A	2015 CDNSADA	44,333.4	-	-	-	[11]
13.	Total non commodity Related Accounts		105,586.4	70.2	(26,640.7)	(47.6)	
	Commodity Related Accounts						
14.	Transactional Services D/A	2014 TSDA	(1,256.7)	(5.6)	(1,256.7)	(11.6)	[12]
15.	Storage and Transportation D/A	2014 S&TDA	(1,147.6)	(10.9)	(1,147.6)	(16.4)	[12]
16.	Unaccounted for Gas V/A	2014 UAFVA	11,917.1	53.4	11,917.1	108.5	[13]
17.	Design Day Criteria Transportation D/A	2014 DDCTDA	12,839.3	112.3	12,839.3	171.3	[14]
18.	Unabsorbed Demand Cost D/A	2014 UDCDA	13,526.2	119.0	13,526.2	181.0	[14]
19.	Total commodity related accounts		35,878.3	268.2	35,878.3	432.8	
20.	Total Deferral and Variance Accounts		141,464.7	338.4	9,237.6	385.2	

Notes:

1. Clearance of the 2014 DSMVA will be requested through a separate application at a later date.
2. DRA evidence is found at Exhibit C, Tab 1, Schedule 8.
3. The forecast clearance amount associated with the 2014 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 7.
4. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
5. Evidence within the B-series of exhibits provides details of Enbridge's 2014 utility results and 2014 earnings sharing calculation.
6. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 10.
7. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 9.
8. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 6.
9. CFBDA evidence is found at Exhibit C, Tab 1, Schedule 11.
10. Clearance of the balance that was recorded in 2014 MGPDA is not being requested at this time. As was indicated in the EB-2014-0276 proceeding, the balance in the 2014 MGPDA was transferred to the 2015 MGPDA.
11. Clearance of the balance that was recorded in 2014 CDNSADA is not being requested at this time. In accordance with the scope of the account that was approved in EB-2012-0459, and as was also indicated in EB-2014-0276, the balance was transferred to the 2015 CDNSADA. The cumulative balance at the end of each year will be transferred to the following year's CDNSADA. At the end of 2018, any residual balance will be requested for clearance in a post 2018 true-up.
12. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 3.
13. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 4.
14. DDCTDA and UDCDA evidence is found at Exhibit C, Tab 1, Schedule 2.

OVERVIEW AND APPROVALS REQUESTED

1. This proceeding addresses Enbridge's request for clearance of the balances in its 2014 Earnings Sharing Mechanism Deferral Account ("ESMDA") and in certain other Deferral and Variance Accounts approved by the Board in prior proceedings.

2. The Board's EB-2012-0459 Decision with Reasons established a Custom IR framework to set Enbridge's rates over the period from 2014 to 2018. Among other things, this includes an ESM under which Enbridge is to share earnings above the Board-approved Return on Equity ("ROE") with ratepayers on a 50/50 basis. The Custom IR framework includes a number of Deferral and Variance Accounts to be maintained or created during the Custom IR term. The Board approved two additional Deferral Accounts for Enbridge within the 2015 Rate Application (EB-2014-0276).

3. Under the Custom IR framework, after the release of its Audited Financial Statements for the prior year Enbridge is required to file an Application setting out the ESM calculation for that year. Within the Application, Enbridge is to set out its proposal for the clearance of amounts within the ESMDA and other Deferral and Variance Accounts.

4. As set out within the EB-2012-0459 Decision with Reasons, Enbridge is also required to annually report upon the status of a number of initiatives and activities as part of its ESM Application.

5. The evidence filed with this Application addresses all required items.

Witnesses: K. Culbert
R. Small

6. The B-series of Exhibits sets out Enbridge's utility financial results for 2014, and includes the calculation of the amount to be credited to ratepayers through the ESM.

7. The C-series of Exhibits provides evidence and explanation for all of the Deferral and Variance Accounts that Enbridge proposes to clear through this Application. The evidence includes a description of the Board-approved scope of each account and an explanation of the balance recorded and being requested for clearance. Within those exhibits, Enbridge also sets out its proposal for the unit rates and timing associated with the clearance of the Deferral and Variance Account balances.

8. The D-series of Exhibits provides the additional reporting information (beyond the overall financial results information) that Enbridge is required to file each year during the Custom IR term. Included within this evidence are the materials that were presented at Enbridge's 2015 Custom IR Stakeholder Day, which was held on April 1, 2015. These Exhibits also address the Company's 2014 Productivity Initiatives Reporting, Status Updates on several major projects and initiatives, the Company's 2014 Service Quality Indicators results and the Company's 2015 Gas Supply Memorandum.

9. The Approvals Requested in this proceeding relate to the clearance of the 2014 ESMDA and certain other Deferral and Variance Accounts.

10. The Company has filed the balances at April 30, 2015 for fiscal year 2014 Board-approved Deferral and Variance Accounts, and the 2015 TIACDA and 2015 CFBDA. The Company requests approval for clearance of certain of these accounts commencing October 1, 2015, and approval to carry forward the balances

in certain other of the accounts for review and approval in a later proceeding. The list of accounts, and the relevant balances, are set out at Appendix A to the Application (Exhibit A, Tab 2, Schedule 1, Appendix A).

11. 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.

12. The Company requests a Board Decision or approval by August 15, 2015, in order to facilitate the clearance of the Deferral and Variance Accounts through a rate rider by specific rate classes within the Company's October 1, 2014 QRAM proceeding.

Witnesses: K. Culbert
R. Small

DRAFT ISSUES LIST

1. Is the amount proposed to be cleared in the 2014 Earnings Sharing Mechanism Deferral Account (ESMDA) appropriate?

2. Are the other Deferral and Variance Accounts balances proposed for disposition as set out in Appendix A to the Application appropriate?

3. What are the appropriate unit rates and timing for implementation of the clearances?

Witness: K. Culbert

CURRICULUM VITAE OF
WILL AKKERMANS

Experience: Enbridge Gas Distribution Inc.

Senior Director, System Operations
2011

General Manager Ottawa – Operations Leadership
2007-2010

Director, Customer Care RFP Project – Customer, Reg. & Public Affairs
2006

General Manager Central Region
2003-2004

Manager Trans Serv/Gas Supp Operations
2000

Manager Special Projects
1999

Manager Supply Management Services
1996-1998

Supervisor Gas Control
1994-1996

Supervisor Pipeline
1993-1994

Pipeline Inspector
1992

Enbridge Inc.

Director, Business Technology
2006

Director, Asset Technology Management
2005-2006

Manager International Business Development
2000-2003

Education: Master of Business Admin, 1999
Bachelor of Science – Civil Engineering, 1993

Memberships: Professional Engineers of Ontario

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-2012-0459 EB-2012-0055 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
JOANNE BARRADAS

Experience:	Enbridge Gas Distribution Inc. Controller, 2014 Ontario Power Generation Inc. Director, Finance 2007 Deloitte Senior Manager, National office 2000 Bank of Montreal and Ernst & Young Various Rolls 1992
Education:	Master of Business Administration (MBA), 2012 Queen’s University Chartered Professional Accountant (CPA, CA), 1998 Chartered Professional Accountants of Ontario Bachelor of Commerce, 1995 University of Toronto
Memberships:	Chartered Professional Accountants of Canada
Appearances:	(Ontario Energy Board) EB-2014-0276

CURRICULUM VITAE OF
DEIRDRE BROUDE, P.Eng

Experience:	Enbridge Gas Distribution Inc.
	Sr. Manager, Asset Management 2015
	Sr. Manager System Integrity 2012
	Manager Technical Training Projects 2011
	Manager Extended Alliance Relationship 2010
	Manager, Operations Business Support 2007
	Manager, Operations, Central Region North 2005
	Manager, Special Projects, Distribution Planning 2002
	Manager, Drafting, Distribution Planning 2001
	Project Manager, Engineering Construction 1998
	Supervisor, Budgets 1997
	Operations Engineer 1993
Education:	Bachelor of Engineering, Mechanical (B.Eng, P.Eng.), 1993 Memorial University of Newfoundland
	Diploma of Nursing, 1987 Western Memorial Hospital, Nfld
Memberships:	Professional Engineers of Ontario
Appearances:	(Ontario Energy Board) None

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-2014-0276	EB-2012-0459	EB-2012-0055
EB-2011-0354	EB-2011-0277	EB-2011-0242
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-3840-2013	R-3793-2012	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.

Senior Manager Regulatory Policy, Strategy & Proceedings
July 2014

Senior Manager Regulatory Accounting
June 2014

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-2014-0276	EB-2012-0459	EB-2012-0055
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
GERALD SCOTT DODD

Experience:

Enbridge Pipelines Inc.
Senior Project Director
MP Mainline Projects
2010

Enbridge Gas Distribution Inc.
Director Ontario Storage Development
2009

Enbridge Solutions Inc.
Director Power Generation
2006

Enbridge Inc.
Director Strategic Planning/Director of Corporate Development
2001

Enbridge Gas Distribution Inc.
Manager Financial Studies
1998

BCE Inc. Montreal, Quebec
Corporate Finance Manager
1997

Repap Enterprises Inc, Montreal, Quebec and Cambellton, New Brunswick
Finance Associate/ Operations Manager
1993

Education:

1993 MBA, University of Western Ontario
1988 BA (Hons) Business Administration, University of Western Ontario
1987 BA Economics, University of Western Ontario

Appearances:

(Ontario Energy Board)
RP-2000-0040
RP-1999-0001

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-2014-0276	EB-2014-0195	EB-2013-0046
EB-2012-0459	EB-2012-0055	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-3793-2012	R-3758-2011	R-3724-2010
R-3665-2008	R-3637-2007	R-3621-2006

CURRICULUM VITAE OF
MATTHEW KIRK

Experience:	Enbridge Gas Distribution Inc.
	Cost Allocation Manager, Regulatory Affairs 2012
	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-2014-0276 EB-2014-0195 EB-2013-0046 EB-2012-0459 EB-2012-0055 EB-2011-0354
	(Régie de L'Energie) R-3884-2014 R-3840-2013 R-3793-2012

CURRICULUM VITAE OF
TARA KATHLEEN KNIGHT, CPA, CA

Experience:	Enbridge Gas Distribution Inc.
	Manager, Capital Management 2012
	Manager, Financial Reporting & Analysis 2008
	Supervisor, External Reporting & Pensions 2006
	Rogers Communications Inc.
	Senior Financial Analyst 2005
	PricewaterhouseCoopers LLP
	Senior Associate 2003
	Cooperative Education Program 2000 - 2002
Education:	Chartered Accountant (CA), 2005
	Master of Accounting, University of Waterloo, 2003
	Honours Bachelor of Arts – Accounting, University of Waterloo, 2002
Memberships:	Institute of Chartered Accountants of Ontario (ICAO)
Appearances	(Ontario Energy Board) None

CURRICULUM VITAE OF
KERRY LAKATOS-HAYWARD

Experience: Enbridge Gas Distribution

Director, Customer Care
2010

Director, Operations Services
2008

Director, Business Development & Strategy
2006

Manager, Business Development & Strategy
2003

Manager, Volumetric & Market Analysis
2000

Manager, Multi-Family Marketing
1997

Senior Economist, Economic Studies
1995

Ontario Hydro

End Use Economist, Load Forecasts
1994

Evaluation Analyst, Planning & Evaluation
1992

Education: Bachelor of Arts (Specialist in Economics)
University of Toronto, 1990

Master of Science in Planning (Environmental Planning)
University of Toronto, 1992

Queen's Executive Program, 2005

Certificate in Carbon Finance, 2008
University of Toronto

Certificate in Sustainable Management 2014
New York Institute of Finance

Appearances: (Ontario Energy Board)

EB-2014-0276	EB-2011-0354	EB-2011-0277
RP-2006-0034	RP-2005-0001	RP-2003-0203
RP-2002-0133	RP-2001-0032	RP-2000-0040
RP-2003-0048		

CURRICULUM VITAE OF
DOUGLAS F. LAPP

Experience: Enbridge Gas Distribution Inc.

Director, Integrity & Process Safety
2015

Director, GTA Project Integration
2014

Director, Operations Strategy & Logistics
2013

Director, Operations Governance and Control
2012

Chief Engineer
2011

Director, Engineering & Construction
2010

Chief Safety Officer
2006

Manager, Chief Operations & Logistics Engineer
2003

General Manager, Niagara Region
2002

Manager, Operations & Engineering Ozz Energy Project
2001

Manager, Distribution Planning
1999

Manager, Year 2000 Business Continuity Planning
1998

Manager, Distribution Operations, Northern Region
1995

Manager, System Regulation
1994

Manager, Engineering Projects
1991

Manager, Planning & Technical Services, Niagara Region
1990

Supervisor, Maintenance, Metro Toronto Region
1989

Senior Distribution Engineer, Congas Engineering Canada Ltd.
1988

Senior Engineer, Operations Engineering
1987

Project Engineer, Eastern Region
1985

Operations Engineer, Operations Engineering
1982

Education: Queens Executive Program, 1998

University of Toronto
Master of Engineering in Welding, 1990

University of Waterloo
Bachelor of Applied Science in Civil Engineering, 1982

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)

EB-2011-0354	EB-2007-0615	EB-2006-0034
RP-2005-0001	RP-2003-0203	RP-2002-0133
RP-2000-0040	RP-1999-0001	EBRO 495

EBRO 487/ EBRO 485
EBLO 241
EBLO 256/EBA 737/EBC 246
EBLO 261/EBA 785/EBC 266
EBA 795

CURRICULUM VITAE OF
JAMIE LeBLANC

Experience:	Enbridge Gas Distribution Inc.
	Director, Energy Supply and Policy 2013
	General Manager - Gazifère Inc. 2010
	Manager, Finance and Control – Enbridge Gas New Brunswick Inc. 2005
	Supervisor, Financial Reporting – Enbridge Gas New Brunswick Inc. 2004
Education:	Chartered Accountancy Designation Atlantic School of Chartered Accountants, 1998
	Bachelor Business Administration University of New Brunswick, Fredericton, 1996
Memberships:	Chartered Professional Accountants New Brunswick
Appearances:	(Ontario Energy Board) EB-2014-0289 EB-2013-0046
	(National Energy Board) RH-001-2013
	(Régie de l'énergie/Régie du gaz naturel) R-3900-2014 R-3884-2014 R-3793-2012 R-3758-2011
	(New Brunswick Energy and Utilities Board) Cost of Capital for Enbridge Gas New Brunswick (EGNB) – 2010 EGNB Financial Results 2009 – 2010 EGNB Cost of Service Study – 2010 EGNB LFO Rate Changes – 2010 EGNB Various Rates and HFO Rates - 2010 EGNB Development Period – 2009 EGNB Financial Results 2008 – 2009 EGNB Financial Results – 2007 - 2009

CURRICULUM VITAE OF
TREVOR MACLEAN

Experience:	Enbridge Gas Distribution Inc.
	Director, Asset Management 2014
	Director, Market Development & Sales 2012
	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-2012-0055 EB-2011-0354

CURRICULUM VITAE OF
IAN B. MACPHERSON

Experience:	Enbridge Gas Distribution Inc.
	Director of Analytics and Business Development 2013
	Senior Manager Storage Development 2011
	Senior Manager Strategic Planning Strategy Research and Planning 2010
	Senior Manager Direct Purchase Customer Care 2008
	Manager Contract Relationships Strategic & Key Accounts 2006
	Senior Account Executive Strategic & Key Accounts 2001
	Energy Solutions Consultant Operations 1998
	Project Engineer Operations 1995
Education:	Bachelor of Science (Mechanical Engineering) Queen’s University, Ontario, Canada, 1991 Certified Industrial Gas Consultant (CIGC)
Memberships:	Professional Engineers Ontario
Appearances	(Ontario Energy Board) None

CURRICULUM VITAE OF
DARREN MCILWRAITH

Experience: Enbridge Gas Distribution Inc.

Senior Manager, Customer Care, Finance and Contract Management
2014

Enbridge Gas Distribution Inc.

Senior Manager, Business Development and DSM Technology
2009

Enbridge Solutions Inc.

Manager, Product Development
2006

Direct Energy Marketing Limited

Director, Customer Analytics
2004

Director, Financial Services
2002

Enbridge Commercial Services Inc.

Director, Financial Services
2001

Enbridge Gas Distribution Inc.

Manager, Budgets
2000

Supervisor, Budgets & Forecasts
1998

Economic Analyst
1996

Education: Master of Arts: Business Economics, Wilfrid Laurier University – 1996
Bachelor of Commerce, University of Guelph - 1994

Appearances: (Ontario Energy Board)
EB-2014-0276
EB-2012-0459

CURRICULUM VITAE OF
BIJU MISRA

Experience: Enbridge Gas Distribution Inc.

Director Information Technology,
2013

Sr. Manager Business Applications,
2009

IT Solution & Support Manager, Information Technology,
2008

Sr. Project Manager, Information Technology,
2007

Project Manager, Information Technology,
2006

Education: Bachelor of Science, Electrical Engineering. Kansas State University
Certificate, Business Management Fundamentals. University of Toronto

Memberships: Project Management Institute (PMI)

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

CURRICULUM VITAE OF
LYNN PARRINGTON

Experience: Enbridge Gas Distribution

Senior Operations Manager, Customer Care
2013

Manager Billing & Meter Reading Services, Customer Care
2009

Manager Customer Contact, Customer Care
2002

Manager Customer Program Admin, Customer Care
2001

Budget Analyst, Customer Care
1997

Customer Service Representative, Customer Care
1995

Education: Bachelor of Commerce (Specialist in Accounting)
University of Ottawa, 1993

Certified Management Accountant
Society of Management Accountants of Ontario, 1998

Appearances: (Ontario Energy Board)
None

CURRICULUM VITAE OF
ASHA PATEL

Experience:	Enbridge Gas Distribution Inc.
	O&M Manager 2014
	Finance Business Partner, IT & Legal 2014
	Supervisor of Capital Management 2012
	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-2011-0008

CURRICULUM VITAE OF
OWEN SCHNEIDER

Experience:	Enbridge Gas Distribution Inc.
	Senior Manager, Project Controls, 2012 Manager, New Ventures, 2009
	Enbridge Solutions Inc.
	Manager, New Ventures, 2008
	Enbridge Inc.
	Manager, Power Generation and Business Development, 2006 Senior Advisor, Business Development, 2004 Advisor, Business and Financial Analysis, 2001 Senior Analyst, Business and Financial Analysis, 2000
	Enbridge Consumers Gas
	Financial Analyst, Financial and Economic Studies, 1997
	Chemque, Inc.
	Project Coordinator, 1995
	Stalko Metals Corporation
	Project Coordinator, 1993
Education:	Masters of Business Administration, 1993
	Bachelor of Arts, 1991
Appearances:	Ontario Energy Board EB-2011-0242 RP-2001-0014

CURRICULUM VITAE OF
JASON SHEM

Experience: Enbridge Gas Distribution Inc.

Supervisor, Financial Reporting
2014

Senior Advisor, Financial Reporting
2012

Financial Analyst
2011

SF Partnership, LLP

Senior Accountant
2009

Ernst & Young

Senior Accountant
2008

Staff Accountant
2007

Education: Chartered Accountant (CA), 2010

Memberships: Institute of Chartered Accountants of Ontario

Appearances: (Ontario Energy Board)
EB-2014-0276
EB-2012-0459

CURRICULUM VITAE OF
DONALD R. SMALL

Experience: Enbridge Gas Distribution Inc.

Manager, Gas Costs and Budget
2010

Manager, Gas Cost Knowledge Centre
2003

Manager, Gas Costs and Budget
1989

Co-ordinator, Gas Costs
1984

Financial Statement Accountant
1980

Chief Clerk, Financial Statements
1979

Advanced Accounting Trainee
1978

Education: Business Administration Diploma
Ryerson Polytechnical Institute, 1978

Appearances: (Ontario Energy Board)

EB-2014-0276	EB-2012-0459	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	RP-1999-0001	EBRO 497
EBRO 495	EBRO 492	EBRO 490
EBRO 487	EBRO 485	EBRO 479
EBRO 473	EBRO 465	

CURRICULUM VITAE OF
RYAN SMALL

Experience: Enbridge Gas Distribution Inc.

Manager, Regulatory Accounting
2014

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: Chartered Professional Accountant, Certified Management Accountant
Chartered Professional Accountants of Ontario, 2014
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-2014-0276
EB-2014-0195
EB-2012-0459
EB-2012-0055
EB-2011-0354
EB-2011-0008

CURRICULUM VITAE OF
LORI STICKLES

Experience: Enbridge Gas Distribution Inc.

Senior Manager Financial Planning and Support
2014

Enbridge Gas New Brunswick Inc.

Manager Corporate Services
2014

Manager, Financial Reporting
2008

Staff Accountant
2004

Education: Chartered Professional Account
2014

Certified General Accountant
2003

Bachelor Business Administration
University of New Brunswick, Fredericton, New Brunswick
1990

Appearances: (Ontario Energy Board)
EB-2014-0276

(New Brunswick Energy and Utilities Board)

Matter 253 – 2015 Rate Application / 2013 Annual Financial Results Review
Matter 225 – 2014 Rate Application / 2012 Annual Financial Results Review
Matter 178 – 2012 Rate Application
Matter 175 – 2011 Annual Financial Results Review
Matter 132 – 2010 Annual Financial Results and Natural Gas Sales Review / 2012 Proposed Budget
Matter 2010-007 – 2009 Annual Financial Results and Natural Gas Sales Review 2011 Proposed Budget

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience: Enbridge Gas Distribution Inc.

Manager, Economic & Market Analysis
2012

Manager, Cost Allocation
2008

Manager, DSM Reporting & Analysis
2005

Analyst, Rate Design
2004

Senior Analyst, DSM Planning and Evaluation
2002

Senior Economic Analyst, Economic & Financial Studies
1998

The Canadian Institute

Conference Producer
1997

Margaret Chase Smith Center for Public Policy

Research Assistant
1995

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

Bachelor of Arts in Economics
University of Maine, 1993

Appearances: (ONTARIO ENERGY BOARD)

EB-2014-0276	EB-2012-0459	EB-2011-0354
EB-2011-0277	EB-2010-0146	EB-2009-0172
EB-2008-0219	EB-2008-0106	

(RÉGIE DE L'ÉNERGIE)

R-3758-2011	R-3724-2010	R-3692-2009
R-3665-2008		

CURRICULUM VITAE OF
ANDREW WELBURN

Experience: Enbridge Gas Distribution Inc.
Manager Gas Supply and Strategy
2014

Manager Upstream Business Partners
2012

Manager Contract Relationships
2008

Manager Operations Performance Reporting
2006

Manager Contract Support and Compliance
2001

Manager Transactional Services Sales
2000

Supervisor Gas Control
1997

Leak Surveyor
1997

Supervisor Pipeline Inspector
1994

Operations Engineer
1994

Load Research Technician
1992

Education: Bachelor of Applied Science in Civil Engineering
University of Waterloo

Memberships: Professional Engineer Ontario
Ontario Society of Professional Engineers

Appearances: (Ontario Energy Board)
EB-2014-0289

(National Energy Board)
MH-001-2013

2014 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. The 2014 Earnings Sharing amount included within Enbridge Gas Distribution Inc's. Fiscal 2014 year-end audited statements was $12.0 million, whereas the amount being requested for approval and clearance within this application is $12.65 million. 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 of dollars 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 following year financial statements. In certain other instances, new information becomes available which requires the earnings sharing amount to be recalculated.

2. The process followed is the same as that which was followed during the 2008 through 2012 incentive regulation term, which at times led to adjustments to the earnings sharing amounts included within the earnings sharing applications, as compared to the year-end financial statements. For 2014, the treatment of Enbridge's April 2014 debt issuance of $300 million has been updated, as compared to the treatment utilized in determining the earnings sharing amount included within the year-end statements. Within the year-end earnings sharing calculation, the $300 million note was categorized as long term debt, but has since been re-categorized to short term debt to correspond with the treatment approved by the Board within the Settlement Agreement in Enbridge's 2015 rate application proceeding, EB-2014-0276. The rationale supporting the re-categorization is

described within the Settlement Agreement at Adjustment 2 (i), found at Exhibit N1, Tab 1, Schedule 1, page 11. The re-categorization resulted in an increase to the earnings sharing amount of $0.6 million.

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

4. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2012-0459 Board Decision, dated July 17, 2014, at pages 13 through 15, and within the pre-filed evidence at Exhibit A2, Tab 7, Schedule 1;
   - if in any calendar year during the customized incentive regulation term, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than the allowed ROE included in that year's rates (updated annually by the application of the Board's ROE Formula), 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 calculation.

5. In addition, the following are examples of shareholder incentives and other amounts which are outside the ambit of the ESM: such as amounts related to Demand Side Management incentives, amounts related to Transactional Services incentives and amounts related to Open Bill program incentives.

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

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

<u>Part A)</u>

8. The level of utility income, $328.6 million (Line 19) divided by the level of utility rate base, $4,701.3 million (Line 24) generates a utility return on rate base of 6.990% (Line 25).

9. When compared to the Company's required rate of return of 6.594% (Line 26), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.396% (Line 27) on total rate base.

10. As shown in Lines 28 through 30, the sufficiency of 0.396% multiplied by the rate base of $4,701.3 million, produces a net over earnings or sufficiency of $18.60 million which from a pre-tax perspective, ($18.60 million divided by the

reciprocal, 73.5%, of the corporate tax rate which is 26.5%) shows a $25.30 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)

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

12. The $334.7 million (Line 33) of utility income before income tax, less utility taxes of $6.1 million (Line 38), produces the $328.6 million of utility income used in part A) above (at Line 19).

13. In order to determine utility net income applicable to a deemed common equity percentage within rate base, all long term debt, short term debt and preference share costs must also be reduced against the part A) $328.6 million utility income.

14. These reductions are shown at Lines 34, 35 and 36 which along with the utility income tax reduction already mentioned and shown at Line 38, results in a net income applicable to common equity of $177.0 million, shown at Line 39.

15. The $177.0 million, divided by the deemed common equity level of $1,692.5 million (Line 40, calculated as 36% of the $4,701.3 million rate base) produces a return on equity of 10.46% (Line 42). When comparing the 10.46% achieved return on equity to the threshold ROE percentage of 9.36% (Line 41), which is the Board approved formula return on equity for 2014, there is a sufficiency in ROE of 1.10% (Line 43).

16. The 1.10% multiplied by the common equity level of $1,692.5 million (Line 40) produces a net over earnings or sufficiency of $18.62 million which from a pre-tax

perspective, ($18.62 million divided by the reciprocal, 73.5%, of the corporate tax rate) shows a $25.33 million total amount of over earnings to be shared equally between ratepayers and the Company. Column 2 provides supporting evidence references.

Process Description

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

18. 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,

19. 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, or are required in order to determine an appropriate utility return on equity. Examples are:
    - rate base disallowance from EBRO 473 and 479 Decisions (Mississauga Southern Link project amounts),
    - rate base disallowance from RP-2002-0133 (shared assets),

- exclusion of non-utility or unregulated activities,
- elimination of approved shareholder incentives.

20. 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 cost of capital information is found in Exhibit B, Tab 5.

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION
ONTARIO UTILITY
(Including CC/CIS)
FOR THE YEAR ENDED DECEMBER 31, 2014

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	2,360.6
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	280.0
4.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,644.9
5.	Gas Distribution Margin		995.7
6.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	1.8
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	43.6
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	0.3
9.	Total - TC&S, Oth. Rev. & Inc.		45.7
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)	(Ex.B,T5,S2,P1,Col.1,line 9)	408.0
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	255.9
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	2.3
13.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 12)	40.5
14.	Total O&M, Depr., & other		706.7
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	334.7
16.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	6.1
17.	**Utility Income**		**328.6**
18.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	7,216.6
19.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(2,900.8)
20.	Net plant		4,315.8
21.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 11)	385.5
22.	**Utility Rate Base**		**4,701.3**
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.990%
24.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	6.594%
25.	(Deficiency) / Sufficiency %		0.396%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	18.60
27.	Provision for Income Taxes		6.70
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	25.30
29.	**50% Earnings sharing to ratepayers**	(line 28 x 50%)	**12.65**
30.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
31.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 16)	334.7
32.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	146.4
33.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	2.8
34.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	2.4
35.	Net Income before Income Taxes		183.1
36.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	6.1
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	177.0
38.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	1,692.5
39.	Approved ROE %		9.360%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	10.460%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.100%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	18.62
43.	Provision for Income Taxes		6.71
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	25.33
45.	**50% Earnings sharing to ratepayers**	(line 44 x 50%)	**12.66**

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

Line No.		Col. 1 2014 Actual Normalized $Millions	Col. 2 2014 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,360.6	2,205.5		
2.	Transportation revenue	280.0	229.2		
3.	Transmission, compression & storage	1.8	1.8		
4.	Gas costs	1,644.9	1,456.3		
5.	Distribution margin	997.5	980.2	17.3	a)
6.	Other revenue	43.6	42.7	0.9	b)
7.	Other income	0.3	0.1	0.2	b)
8.	O&M (incl. CC/CIS rate smoothing adj.)	408.0	422.4	14.4	c)
9.	Depreciation expense	255.9	248.5	(7.4)	d)
10.	Other expense	42.8	43.1	0.3	e)
11.	Income taxes	6.1	8.9	2.8	f)
12.	Utility Income	328.6	300.1	28.5	
13.	LTD & STD costs	149.2	148.3	(0.9)	g)
14.	Preference share costs	2.4	3.0	0.6	g)
15.	Return on Equity @ 9.36% in 2014 Board Approved	158.4	148.8	(9.6)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	18.6	-	18.6	
17.	Provision for taxes on Earnings Over / (Under)	6.7	-	6.7	
18.	Gross Earnings Over / (Under)	25.3	-	25.3	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,692.5			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	177.0			
21.	EGD normalized Return on Equity	10.46%			

2014 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

The following are explanations of the Utility Normalized Earnings results as compared to the 2014 Board Approved amounts. The reference letters are in relation to those identified on page 1 of this schedule.

a) The distribution margin increase of $17.3 million is mainly driven by a favourable customer variance, or higher average customer unlocks, higher PGVA reference prices approved though the QRAM's resulting in the recovery of higher carrying charges, higher contract demand revenues due to favourable rate class migration and higher annual minimum bill charges, and lower cost associated with the fuel required to manage storage operations and the transmission of volumes on Union's system. This results in a positive earnings impact.

b) The increase in other revenue and other income of $1.1 million is mainly due to higher late payment penalty revenues, which were higher than approved due to higher customer bills caused by colder than normal weather and higher than budgeted gas prices. This results in a positive earnings impact. Details of other revenue and other income are presented in Exhibit B, Tab 3, Schedule 5.

c) Utility O&M is $14.4 million lower than the 2014 Board approved level, resulting in a positive earnings impact. Explanations of the major changes between actual O&M and Board approved are presented in Exhibit B, Tab 4, Schedule 2.

d) The increase in depreciation expense of $7.4 million is predominantly due to higher depreciable property, plant and equipment balances in place throughout 2014, versus Board approved. The higher balances were largely due to higher opening balances which reflected 2012 and 2013 actual results, which were not reflected in the forecast 2014 property, plant and equipment balances. The increase in depreciation results in a reduction in earnings.

Witness: R. Small

e) The other expenses reduction of $0.3 million is the result of lower municipal taxes, partially offset by an increase in fixed financing costs resulting from the Company increasing its credit facility. The net result is an increase in earnings.

f) The reduction in income taxes of $2.8 million is predominantly due to higher than forecast tax deductible amounts for CCA and cost of retirements, offset by a higher utility income before tax amount resulting from the above noted items. The reduction results in a positive earnings impact.

g) The interest cost of utility long and short term debt increased by $0.9 million as a result of a higher outstanding principal balance required to fund a higher than forecast rate base value. The impact of the higher principal balance was largely offset by lower realized average cost rates. The preference share costs decreased by $0.6 million, relative to the 2014 approved amount, as a result of a lower than forecast prime interest rate in 2014. The net impact has a negative earnings impact.

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2014 ACTUAL

Line no.		Col. 1 Audited Consolidated Income ($millions)	Col. 2 Utility Income ($millions)	Col. 3 Difference ($millions)	Col. 4 Reference
1.	Gas commodity and distribution revenue	2,802.5	2,360.6	(441.9)	a)
2.	Transportation of gas for customers	305.2	280.0	(25.2)	b)
3.		3,107.7	2,640.6	(467.1)	
4.	Gas commodity and distribution costs	2,046.1	1,644.9	(401.2)	c)
5.	Gas distribution margin	1,061.6	995.7	(65.9)	
6.	Other revenue and income	158.3	45.7	(112.6)	d)
7.		1,219.9	1,041.4	(178.5)	
	Expenses				
8.	Operation and maintenance	491.5	408.0	(83.5)	e)
9.	Earnings sharing	12.0	-	(12.0)	f)
10.	Depreciation	285.9	255.9	(30.0)	g)
11.	Municipal and other taxes	-	40.5	40.5	h)
13.		789.4	704.4	(85.0)	
14.	Income before undernoted items	430.5	337.0	(93.5)	
15.	Interest and financing expenses	(177.3)	(2.3)	175.0	i)
16.	Income before income taxes	253.2	334.7	81.5	
17.	Income taxes	(6.5)	(6.1)	0.4	j)
18.	Net Income	246.7	328.6	81.9	

RECONCILIATION OF 2014
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	2,802.5	**Consolidated gas commodity and distribution revenue**
	(41.4)	Amounts related to St. Lawrence Gas
	(204.6)	Normalization adjustment
	(197.5)	US GAAP adjustment elimination - deferral clearance adjustment
	0.4	Elimination of 2013 OHCVA write-off as per the EB 2014-0195 decision
	1.2	Gazifere T-service regrouped to gas commodity and distribution revenue
	2,360.6	**Utility gas commodity and distribution revenue**
b)	305.2	**Consolidated transportation of gas for customers**
	(9.6)	Amounts related to St. Lawrence Gas
	(14.3)	Normalization adjustment
	(1.2)	Gazifere T-service regrouped to gas commodity and distribution revenue
	(0.1)	Rounding
	280.0	**Utility transportation of gas for customers**
c)	2,046.1	**Consolidated gas commodity and distribution costs**
	(36.5)	Elimination of amounts related to St. Lawrence Gas, unregulated storage
	(170.6)	Normalization adjustment
	(194.1)	US GAAP adjustment elimination - deferral clearance adjustment
	1,644.9	**Utility gas commodity and distribution costs**

RECONCILIATION OF 2014
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	158.3	**Consolidated other revenue and income**
	(19.7)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(62.7)	Elimination of non-utility dividend income from the Board Approved financing transaction
	(0.1)	NGV merchandising costs regrouped against program revenues from O&M
	0.7	Foreign exchange loss and other misc. expenses regrouped to O&M
	5.7	Allowable interest during construction regrouped to revenues from interest and financing expenses
	8.6	Interest on deferral accounts regrouped to revenues from interest and financing expenses
	(2.4)	ABC administration and bad debt costs regrouped against program revenues from O&M
	(0.1)	ABC interest charges regrouped against program revenues from interest and financing expenses
	(12.3)	Open Bill expenses regrouped against program revenues from O&M
	(1.7)	Electric CDM costs regrouped against program revenues from O&M
	(1.4)	Elimination of transactional services revenue above base amount included in rates
	(1.0)	To adjust OBA costs to reflect the EB-2013-0099 approved unit costs for determining net revenues
	(1.3)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(1.4)	Elimination of 3rd party asset use revenue considered non-utility
	(2.3)	Elimination of net ABC revenue considered non-utility
	(1.0)	Elimination of interest income from investments not included in rate base
	(5.7)	Elimination of allowable interest during construction
	(8.6)	Elimination of interest on deferral accounts
	(2.0)	To eliminate GST overpayment recovery from Accenture
	(3.8)	Elimination of shareholder incentive income associated with the DSMIDA
	(0.1)	Rounding
	45.7	**Utility other revenue and income**
e)	491.5	**Consolidated operation and maintenance**
	(43.4)	Municipal and other taxes included within O&M costs in the corp. financial statements
	(12.4)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(12.3)	Open Bill expenses regrouped against program revenues
	(2.4)	ABC administration and bad debt costs regrouped against program revenues and eliminated
	(1.7)	Electric CDM expenses regrouped against program revenues
	(0.1)	NGV merchandising costs regrouped against program revenues
	0.7	Foreign exchange loss and other misc. expenses regrouped from Other income
	0.9	Interest on security deposits added to utility O&M
	(1.2)	Elimination of donations
	(1.6)	Elimination of non-utility costs of supporting the ABC program
	0.1	Elimination of the correction of the 2013 DSMVA amount recorded in 2014
	(3.4)	US GAAP adjustment elimination - deferral clearance adjustment
	(6.7)	Elimination of Corporate Cost Allocations above RCAM amount
	408.0	**Utility operation and maintenance**
f)	12.0	**Consolidated earnings sharing**
	(12.0)	Elimination of 2014 earnings sharing amount within year end financials from utility income calculation
	-	**Utility earnings sharing**

RECONCILIATION OF 2014
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
g)	285.9	**Consolidated depreciation**
	(6.7)	Amounts related to St. Lawrence Gas, unregulated storage, and oil and gas
	(22.5)	Elimination of the amortization of PPD
	(0.1)	Elimination of depreciation on disallowed Mississauga Southern Link
	(0.7)	Elimination of depreciation related to shared assets
	255.9	**Utility depreciation**
h)	-	**Consolidated municipal and other taxes**
	43.4	Municipal and other taxes included within O&M costs in the corp. financial statements
	(2.7)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	40.5	**Utility municipal and other taxes**
i)	177.3	**Consolidated interest and financing expenses**
	(3.2)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(26.8)	Elimination of non-utility interest expense from the Board Approved financing transaction
	5.7	Allowable interest during construction regrouped to revenues and eliminated
	8.6	Interest on deferral accounts regrouped to revenues and eliminated
	(0.1)	ABC interest charges regrouped against program revenues and eliminated
	(159.2)	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure
	2.3	**Utility interest and financing expenses**
j)	6.5	**Consolidated income taxes**
	(3.2)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(3.3)	Elimination of corporate income taxes
	6.1	Addition of income taxes calculated on a utility "stand-alone" basis
	6.1	**Utility income taxes**

UTILITY RATE BASE (INCLUDING CUSTOMER CARE & CIS)
COMPARISON OF 2014 ACTUAL TO 2014 BOARD APPROVED

Line No.		Col. 1 2014 Actual	Col. 2 2014 Board Approved	Col. 3 Difference
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	7,216.6	7,104.1	112.5
2.	Accumulated depreciation	(2,900.8)	(2,941.1)	40.3
3.	Net property, plant, and equipment	4,315.8	4,163.0	152.8
	Allowance for Working Capital			
4	Accounts receivable rebillable projects	1.3	1.3	-
5	Materials and supplies	35.5	32.8	2.7
6.	Mortgages receivable	0.1	0.1	-
7.	Customer security deposits	(61.4)	(65.7)	4.3
8.	Prepaid expenses	1.3	0.9	0.4
9.	Gas in storage	402.7	279.9	122.8
10.	Working cash allowance	6.0	9.1	(3.1)
11.	Total Working Capital	385.5	258.4	127.1
12.	Utility Rate Base	4,701.3	4,421.4	279.9

UTILITY PROPERTY, PLANT, AND EQUIPMENT (INCLUDING CUSTOMER CARE & CIS)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

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	359.6	(128.1)	231.5
2.	Distribution plant	6,400.6	(2,552.1)	3,848.5
3.	General plant	466.4	(220.5)	245.9
4.	Other plant	0.5	(0.5)	-
5.	Total plant in service	7,227.1	(2,901.2)	4,325.9
6.	Plant held for future use	1.7	(1.2)	0.5
7.	Sub- total	7,228.8	(2,902.4)	4,326.4
8.	Affiliate Shared Assets Value	(12.2)	1.6	(10.6)
9.	Total property, plant, and equipment	7,216.6	(2,900.8)	4,315.8

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2014	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)	44.5	1.4	-	45.9	(1.0)	44.9	43.7
3.	Structures and improvements (452.00)	15.5	2.0	-	17.5	(0.1)	17.4	15.8
4.	Wells (453.00)	47.0	1.1	-	48.0	-	48.0	47.3
5.	Well equipment (454.00)	9.9	0.4	-	10.3	-	10.3	10.0
6.	Field Lines (455.00)	78.2	1.3	-	79.5	-	79.5	78.8
7.	Compressor equipment (456.00)	106.2	3.7	-	109.9	(0.5)	109.4	107.4
8.	Measuring and regulating equipment (457.00)	11.6	-	-	11.6	-	11.6	11.6
9.	Base pressure gas (458.00)	40.9	0.0	-	40.9	-	40.9	40.9
10.	Total	357.9	9.8	-	367.7	(1.5)	366.2	359.6

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

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2014	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2014	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.3)	(0.1)	-	-	-	(2.4)	-	(2.4)	(2.3)
2.	Land and gas storage rights (451.00)	(22.3)	(0.5)	-	-	-	(22.8)	-	(22.8)	(22.6)
3.	Structures and improvements (452.00)	(5.7)	(0.3)	-	-	-	(6.0)	0.1	(6.0)	(5.8)
4.	Wells (453.00)	(21.4)	(0.7)	(0.0)	-	-	(22.1)	-	(22.1)	(21.7)
5.	Well equipment (454.00)	(5.5)	(0.6)	-	-	-	(6.1)	-	(6.1)	(5.8)
6.	Field Lines (455.00)	(23.7)	(1.2)	(0.0)	-	-	(24.9)	-	(24.9)	(24.3)
7.	Compressor equipment (456.00)	(37.9)	(2.9)	(0.1)	-	-	(40.9)	0.2	(40.7)	(39.3)
8.	Measuring and regulating equipment (457.00)	(6.2)	(0.4)	(0.0)	-	-	(6.5)	-	(6.5)	(6.3)
9.	Total	(125.0)	(6.7)	(0.1)	-	-	(131.7)	0.3	(131.5)	(128.1)

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

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	19.1	0.3	-	19.4	-	19.4	19.2
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	7.5	3.7	-	11.1	-	11.1	7.6
4.	Structures and improvements (472.00)	126.7	3.3	-	129.9	(0.3)	129.6	127.4
5.	Services, house reg & meter install. (473/474)	2,347.2	136.1	(7.4)	2,475.9	-	2,475.9	2,401.5
6.	NGV station compressors (476)	3.2	0.3	(0.4)	3.1	-	3.1	3.2
7.	Meters (478)	405.1	22.0	(12.4)	414.7	-	414.7	405.7
8.	Sub-total	2,908.7	165.6	(20.1)	3,054.1	(0.3)	3,053.8	2,964.6
9.	Mains (475)	2,929.9	242.3	(3.8)	3,168.4	(2.2)	3,166.2	3,054.3
10.	Measuring and regulating equip. (477)	366.0	33.6	(0.6)	399.0	(0.5)	398.5	381.7
11.	Sub-total	3,295.9	275.9	(4.4)	3,567.4	(2.7)	3,564.7	3,436.0
12.	Total	6,204.5	441.5	(24.6)	6,621.5	(3.1)	6,618.4	6,400.6

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

UTILITY DISTRIBUTION PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2014	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2014	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(1.9)	(0.1)	-	-	-	(2.0)	-	(2.0)	(2.0)
2.	Structures and improvements (472.00)	(15.6)	(7.9)	-	-	-	(23.5)	0.2	(23.3)	(19.4)
3.	Services, house reg & meter install. (473/474)	(1,017.9)	(55.0)	32.8	7.4	10.4	(1,022.3)	-	(1,022.3)	(1,018.1)
4.	NGV station compressors (476)	(2.2)	(0.2)	-	0.4	-	(2.0)	-	(2.0)	(2.3)
5.	Meters (478)	(121.5)	(37.5)	-	12.4	(1.0)	(147.5)	-	(147.5)	(135.1)
6.	Mains (475)	(1,192.6)	(66.4)	63.8	3.8	15.5	(1,176.0)	1.6	(1,174.4)	(1,178.5)
7.	Measuring and regulating equip. (477)	(193.5)	(8.3)	0.4	0.6	-	(200.8)	0.5	(200.2)	(196.8)
8.	Total	(2,545.2)	(175.3)	97.0	24.6	24.9	(2,574.1)	2.3	(2,571.8)	(2,552.1)

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

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	5.6	0.8	-	6.4	(0.2) [1]	6.2	5.6
2.	Office furniture and equipment (483.00)	18.4	3.0	(2.5)	18.9	-	18.9	19.2
3.	Transportation equipment (484.00)	50.8	3.0	(0.7)	53.1	(0.1) [1]	53.1	50.9
4.	NGV conversion kits (484.01)	8.9	-	-	8.9	-	8.9	8.9
5.	Heavy work equipment (485.00)	19.2	2.6	(0.0)	21.7	-	21.7	19.2
6.	Tools and work equipment (486.00)	38.6	12.3	(2.8)	48.0	-	48.0	39.0
7.	Rental equipment (487.70)	1.0	0.0	-	1.1	-	1.1	1.0
8.	NGV rental compressors (487.80)	3.8	0.1	(1.2)	2.7	-	2.7	3.8
9.	NGV cylinders (484.02 and 487.90)	2.5	-	-	2.5	-	2.5	2.5
10.	Communication structures & equip. (488)	3.0	-	-	3.0	-	3.0	3.0
11.	Computer equipment (490.00)	35.9	3.7	-	39.6	-	39.6	37.4
12.	Software Aquired/Developed (491.00)	141.9	32.3	-	174.1	-	174.1	148.7
13.	CIS (491.00)	127.1	-	-	127.1	-	127.1	127.1
14.	Total	456.7	57.6	(7.3)	507.1	(0.3)	506.8	466.4

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

UTILITY GENERAL PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013 ($Millions)	Col. 2 Additions ($Millions)	Col. 3 Retirements ($Millions)	Col. 4 Costs Net of Proceeds ($Millions)	Col. 5 Closing Balance Dec.2014 ($Millions)	Col. 6 Regulatory Adjustment ($Millions)	Col. 7 Utility Balance Dec.2014 ($Millions)	Col. 8 Average of Monthly Averages ($Millions)
1.	Lease improvements (482.50)	(4.2)	(0.7)	-	-	(4.9)	0.2 [1]	(4.7)	(4.3)
2.	Office furniture and equipment (483.00)	(4.4)	(2.1)	2.5	-	(4.0)	-	(4.0)	(5.4)
3.	Transportation equipment (484.00)	(16.0)	(5.4)	0.7	(0.2)	(20.9)	0.1 [1]	(20.8)	(18.3)
4.	NGV conversion kits (484.01)	(5.7)	(0.8)	-	-	(6.5)	-	(6.5)	(6.1)
5.	Heavy work equipment (485.00)	(7.6)	(0.7)	0.0	(0.0)	(8.3)	-	(8.3)	(8.0)
6.	Tools and work equipment (486.00)	(16.7)	(1.6)	2.8	-	(15.5)	-	(15.5)	(17.4)
7.	Rental equipment (487.70)	(1.0)	-	-	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.9)	(0.3)	1.2	(0.2)	(2.1)	-	(2.1)	(3.0)
9.	NGV cylinders (484.02 and 487.90)	(2.0)	(0.3)	-	-	(2.3)	-	(2.3)	(2.2)
10.	Communication structures & equip. (488)	(2.4)	(0.1)	-	-	(2.5)	-	(2.5)	(2.4)
11.	Computer equipment (490.00)	(7.8)	(13.6)	-	-	(21.4)	-	(21.4)	(14.4)
12.	Software Aquired/Developed (491.00)	(60.7)	(36.1)	-	-	(96.9)	-	(96.9)	(77.7)
13.	CIS (491.00)	(54.0)	(12.7)	-	-	(66.7)	-	(66.7)	(60.4)
14.	Total	(185.5)	(74.4)	7.3	(0.4)	(252.9)	0.2	(252.7)	(220.5)

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

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2014	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	-	0.5	-	0.5	0.5
2.	Total	0.5	-	-	0.5	-	0.5	0.5

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2014	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2014	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)
2.	Total	(0.5)	-	-	-	(0.5)	-	(0.5)	(0.5)

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2014	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2014	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

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2013	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2014	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2014	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.2)	(0.0)	-	-	(1.2)	-	(1.2)	(1.2)
2.	Total	(1.2)	(0.0)	-	-	(1.2)	-	(1.2)	(1.2)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Account Receivable Rebillable Projects	Col. 2 Materials and Supplies	Col. 3 Mortgages Receivable	Col. 4 Customer Security Deposits	Col. 5 Prepaid Expenses	Col. 6 Gas in Storage	Col. 7 Working Cash Allowance	Col. 8 Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	January 1	1.8	34.9	0.1	(62.0)	0.7	413.8	6.0	395.3
2.	January 31	1.3	34.8	0.1	(62.1)	1.8	272.7	6.0	254.6
3.	February	1.3	36.0	0.1	(62.0)	1.6	186.2	6.0	169.2
4.	March	1.3	36.6	0.1	(61.8)	1.5	130.7	6.0	114.4
5.	April	1.3	35.4	0.1	(61.6)	1.3	177.2	6.0	159.7
6.	May	1.3	35.9	0.1	(60.8)	1.1	276.1	6.0	259.7
7.	June	1.3	35.6	0.1	(60.3)	1.4	391.1	6.0	375.2
8.	July	1.3	34.6	0.1	(60.2)	1.4	496.7	6.0	479.9
9.	August	1.3	32.4	0.1	(60.8)	1.3	574.2	6.0	554.5
10.	September	1.3	34.3	0.1	(61.1)	1.2	641.9	6.0	623.7
11.	October	1.2	35.9	0.1	(61.8)	1.0	599.2	6.0	581.6
12.	November	1.2	37.6	0.1	(62.3)	0.9	603.4	6.0	586.9
13.	December	1.2	38.0	0.1	(60.8)	1.6	553.0	6.0	539.1
14.	Avg. of monthly avgs.	1.3	35.5	0.1	(61.4)	1.3	402.7	6.0	385.5

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2014 ACTUAL

		Col. 1	Col. 2	Col. 3
Line No.		Disbursements	Net Lag-Days	Allowance
		($Millions)	(Days)	($Millions)
1.	Gas purchase and storage and transportation charges	1,661.3	2.3	10.5
2.	Items not subject to working cash allowance (Note 1)	(16.4)		
3.	Gas costs charged to operations	1,644.9		
4.	Operation and Maintenance	408.0		
5.	Less: Storage costs	(7.2)		
6.	Operation and maintenance costs subject to working cash	400.8		
7.	Ancillary customer services	-		
8.		400.8	(11.0)	(12.1)
9.	Sub-total			(1.6)
10.	Storage costs	7.2	65.9	1.3
11.	Storage municipal and capital taxes	1.3	23.3	0.1
12.	Sub-total			1.4
13.	Harmonized Sales Tax			6.2
14.	Total working cash allowance			6.0

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

Comparison of Utility Capital Expenditures
2014 Actuals vs. 2014 Board Approved Budget

Table 1
Summary of Capital Expenditures 2014 Actual and 2014 Board Approved Budget
($millions)

Item		Col 1 Actual 2014	Col 2 Board Approved Budget 2014	Col 3 Actual Over/(Under) 2014
A	Customer Related Distribution Plant	160.2	122.4	37.8
B	System Improvements and Upgrades	184.5	243.2	(58.7)
C	General and Other Plant	54.5	56.3	(1.8)
D	Underground Storage Plant	13.4	21.9	(8.5)
E	**Sub total Core Capital Expenditures**	**412.6**	**443.8**	**(31.2)**
F	Work and Asset Management Solution (WAMS)	19.6	36.3	(16.7)
G.1	Leave to Construct - GTA Reinforcement	172.4	226.3	(53.9)
G.2	Leave to Construct - Ottawa Reinforcement	7.7	5.1	2.6
H	**Sub total Special Initiatives**	**199.7**	**267.7**	**(68.0)**
I	**Total Capital Expenditures**	**612.3**	**711.5**	**(99.2)**

1. The 2014 Actual expenditures for Work and Asset Management (“WAMS”) and Leave to Construct projects totaled $199.7 million, which was $68.0 million or 25.4% less than the 2014 Budget of $267.7 million. This underspend is due to timing as these are multi-year initiatives that have experienced some delays. Total spending on the WAMS and GTA Reinforcement projects is expected to catch up to (and exceed) budgeted spend. Neither the WAMS or GTA Reinforcement projects had a rate making or rate base impact in 2014 as they were not forecast to be completed and in-service by end of 2014.

2. The 2014 Actual core capital expenditures were $412.6 million, which was $31.2 million or 7.0% less than the 2014 Budget of $443.8 million. Core capital

includes overheads (i.e., departmental labour costs, capitalized administrative and general, and interest during construction). Excluding overheads, the 2014 Actual core capital spend was $306.8 million or 5.8% less than the 2014 Budget of $325.8 million.

3. Table 2 below shows the major drivers of the $99.2 million total 2014 capital underspend vs. Board approved budget. Further details are provided below.

Table 2
2014 Actual vs. 2014 Board Approved Budget - Major Variance Drivers
($millions)

		Actual Over/(Under)	% Over / (Under)	Commentary
	Total 2014 Variance	**(99.2)**	**-14%**	
	Breakdown of Variance by Major Driver			
A	LTC -GTA Reinforcement	(53.9)	-24%	Start up delays, does not impact rate base in 2014
B	WAMS	(16.7)	-46%	Start up delays, does not impact rate base in 2014
C	Relocation Mains	(14.4)	-95%	Higher 3rd Party recoveries
D	Overheads -Departmental Labour Costs, A&G and IDC	(12.2)	-10%	Delay in filling vacancies, less than anticipated Interest During Construction
E	Information Technology	(9.3)	-32%	Evolving business needs (delay of applications and enhancements)
F	Storage	(8.0)	-42%	Delayed construction of compressor plant
G	Reinforcements	(7.8)	-68%	Delays due to external factors
H	System Integrity and Reliability	(6.4)	-5%	Delays due to external factors
I	Customer Growth	24.6	27%	Higher unit costs due to 3rd party cost pressures and customer mix
J	Facilities	6.1	26%	Evolving business needs (accelerated replacement of tools and fleet equipment)
K	Other	(1.2)	-14%	
		(99.2)	**-14%**	

A - Leave To Construct GTA Reinforcement – Underspent by $53.9 Million

4. The GTA Reinforcement project (Leave to Construct application EB-2012-0099) is a multi-year infrastructure project with expected completion in Q4 of 2015. As a result, there is no rate impact in 2014 from the underspend as the project will not be in service until Q4 of 2015. The

project was delayed in 2014 due to logistical challenges of the material (42 inch steel pipe) delivery from Europe. The delay in material shipments had a direct impact resulting in lower labour and overhead costs. As well, land right costs were lower than budgeted. 2015 is the key construction and spend year when virtually all work will be completed. The project total is expected to be $756 million, which exceeds the project budget of $686 million. Please see Exhibit D, Tab 1, Schedule 2 for more details.

B - Work and Asset Management Solution (WAMS) – Underspent by $16.7 Million

5. WAMS is a fundamental business tool foundational to providing safe and reliable service to Enbridge's utility customers. This is a multi-year initiative which began with planning and design in 2014, design, build and test will occur in 2015, and further testing and "go live" is planned for Q2 2016. Delayed spend in 2014 was due to a delay in starting the implementation phase. The overall project spend is expected to catch up to budget by the project completion in 2016. Please see Exhibit D, Tab 1, Schedule 3 for more details.

C - Relocation Mains – Underspent by $14.4 Million

6. There were higher recoveries for 3rd party relocation activity in 2014 than budgeted due to customer mix and the implementation of an accounting policy change to accrue 3rd party rebillables during the construction process instead of at project completion.

D - Departmental Labour Costs, A&G and IDC – Underspent by $12.2 Million

7. From an overall perspective, these three cost categories were 10% less than budget. The Company has reduced FTEs from the budgeted level, as part of its

productivity efforts as per its commitment under the Customized IR application. This is described within Exhibit D, Tab 2, Schedule 1. This productivity effort with Departmental Labour Costs accounts for $7.8 million of the underage. Interest during construction ("IDC") is a function of the timing of actual construction costs. Due to the delay of some projects, actual IDC was $4.1 million less than the budget.

E - Information Technology – Underspent by $9.3 Million

8. This variance is indicative of the Company's efforts to respond to evolving business conditions. Underspending in computer requirements was due to delayed business applications and software enhancements.

F - Storage – Underspent by $8.0 Million

9. The 2014 storage plant expenditures were less than budget primarily due to the delay in construction of the compressor plant ($6.6 million). Completion of the compressor plant is expected in 2015. The remaining underage is due to completing only one out of two planned observation wells.

G - Reinforcements – Underspent by $7.8 Million

10. There was less reinforcement work as a result of numerous external factors, such as permitting delays, land easement availability and alignment with municipal schedules. Additionally, actual growth was considerably less than budgeted growth, which was based on forecasts received from developers.

H - System Integrity and Reliability (SIR) – Underspent by $6.4 Million

11. There was less SIR work as a result of numerous external factors. For example with regards to Measurement and Regulation station activity, the Cookstown gate station ($2.7 million) was deferred pending a land acquisitions and the Keele/Finch

station ($1.8 million) replacement was deferred due to TTC work currently on site. External factors such as these are beyond the Company's control. Please see Exhibit D, Tab 1, Schedule 4 for further details.

I - Customer Growth – Overspent by $24.6 Million

12. The cost of adding new customers increased due to higher direct costs related to customer mix and higher unit costs. The cost pressure challenges include increased municipal fees, full year construction and managing geographic sectors. Rising municipal and permitting fees are costs that are beyond the Company's control. Construction during extreme weather conditions and geographic challenges have a direct impact on the unit cost of adding new customers. The mix of more expensive replacement customers vs. new construction (subdivision) customers also factor heavily into the cost equation.

J - Facilities – Overspent by $6.1 Million

13. This variance is indicative of the Company's efforts to respond to evolving business conditions. Tools and fleet equipment replacements were accelerated to meet safety and reliability concerns. This was partially offset by underspending in building facilities redesign due to reductions in FTEs.

UTILITY OPERATING REVENUE (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	2,565.2	(204.6)	2,360.6
2.	Transportation of gas	294.3	(14.3)	280.0
3.	Transmission, compression & storage	1.8	-	1.8
4.	Other operating revenue	43.6	-	43.6
5.	Interest and property rental	-	-	-
6.	Other income	0.3	-	0.3
7.	Total operating revenue	2,905.2	(218.9)	2,686.3

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2014 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(204.6)	Gas sales Adjustment to gas sales revenue required to reflect normal weather.
2.	(14.3)	Transportation of gas Adjustment to gas transportation revenue required to reflect normal weather.

UTILITY REVENUE (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

Line No.		Col. 1 EGDI Ont. Corporate Revenue ($Millions)	Col. 2 Adjustment ($Millions)	Col. 3 Utility Revenue ($Millions)
1.	Residential	1,806.4	(197.1)	1,609.3
2.	Commercial	824.6	-	824.6
3.	Industrial	100.1	-	100.1
4.	Wholesale	31.2	-	31.2
5.	Gas sales	2,762.3	(197.1)	2,565.2
6.	Transportation of gas	294.3	-	294.3
7.	Transmission, compression & storage	1.8	-	1.8
8.	Service charges & DPAC	12.5	-	12.5
9.	Rent from NGV rentals	0.4	-	0.4
10.	Late payment penalties	13.1	-	13.1
11.	Transactional services	13.4	(1.4)	12.0
12.	Open bill revenue	7.7	(2.3)	5.4
13.	Dow Moore recovery	0.2	-	0.2
14.	Affiliate asset use revenue	-	-	-
15.	ABC T-service (net)	2.3	(2.3)	-
16.	Other operating revenue	49.6	(6.0)	43.6
17.	Income from investments	1.0	(1.0)	-
18.	Interest during construction	5.7	(5.7)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	8.6	(8.6)	-
21.	Property/asset use revenue 3rd party	1.4	(1.4)	-
22.	Interest and property rental	16.7	(16.7)	-
23.	Miscellaneous	14.6	(14.3)	0.3
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	77.3	(77.0)	0.3
28.	Total revenue	3,202.0	(296.8)	2,905.2

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2014 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	(197.1)	Residential gas sales	
		Eliminate 2013 OHCVA write-off as per EB-2014-0195 decision.	0.4
		US GAAP adjustment elimination, deferral & variance clearance recognition.	(197.5)
			(197.1)
11.	(1.4)	Transactional services	
		To eliminate transactional services revenues above the base amount included in rates. Ratepayer and shareholder amounts above the base are treated outside of utility results and returns.	
12.	(2.3)	Open bill revenue	
		To adjust OBA costs to reflect the EB-2013-0099 approved unit costs agreed to be used for determining net revenues.	(1.0)
		To eliminate the Open Bill shareholder incentive.	(1.3)
			(2.3)
15.	(2.3)	ABC T-Service (net)	
		To eliminate the net revenue from ABC T-Service considered to be non-utility. (RP-1999-0001)	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2014 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(1.0)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(5.7)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
18.	(8.6)	Interest on (net) deferral accounts	
		To eliminate interest income from assets not included in Utility rate base.	
21.	(1.4)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(14.3)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(8.5)
		To eliminate GST overpayment recovery from Accenture. Original GST overpayment write-off was a non-utility expense in 2007.	(2.0)
		To eliminate 2012 DSMIDA amount which was written-off as per the EB-2013-0352 Decision.	0.7
		To eliminate the shareholders' incentive income recorded as a result of calculating the 2013 DSMIDA amount.	(4.5)
			(14.3)
24.	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2014 ACTUAL AND 2014 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2014 Actual	Col. 2 2014 Board Approved Budget	Col. 3 2014 Actual Over (Under) 2014 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	4 791.1	4 131.1	660.0
1.1.2	Rate 1 - T-Service	589.8	490.2	99.6
1.1	Total Rate 1	5 380.9	4 621.3	759.6
1.2.1	Rate 6 - Sales	3 187.3	2 944.7	242.6
1.2.2	Rate 6 - T-Service	2 134.6	1 625.5	509.1
1.2	Total Rate 6	5 321.9	4 570.2	751.7
1.3.1	Rate 9 - Sales	0.5	0.5	0.0
1.3.2	Rate 9 - T-Service	0.1	0.1	0.0
1.3	Total Rate 9	0.6	0.6	0.0
1.	Total General Service Sales & T-Service	10 703.4	9 192.1	1 511.3
Contract Sales				
2.1	Rate 100	3.3	0.0	3.3
2.2	Rate 110	87.2	92.1	(4.9)
2.3	Rate 115	1.0	0.9	0.1
2.4	Rate 135	4.6	1.2	3.4
2.5	Rate 145	19.1	22.0	(2.9)
2.6	Rate 170	37.9	37.3	0.6
2.7	Rate 200	183.2	164.9	18.3
2.	Total Contract Sales	336.3	318.4	17.9
Contract T-Service				
3.1	Rate 100	1.1	0.0	1.1
3.2	Rate 110	441.2	525.6	(84.4)
3.3	Rate 115	538.4	470.1	68.3
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	58.1	55.3	2.8
3.6	Rate 145	122.6	142.0	(19.4)
3.7	Rate 170	417.0	425.6	(8.6)
3.8	Rate 300	38.4	30.0	8.4
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 616.8	1 648.6	(31.8)
4.	Total Contract Sales & T-Service	1 953.1	1 967.0	(13.9)
5.	Total	12 656.5	11 159.1	1 497.4

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2014 ACTUAL AND 2014 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2014 Actual	Col. 2 2014 Board Approved Budget	Col. 3 2014 Actual Over (Under) 2014 Budget (1-2)	Col. 4 2014* Adjustments	Col. 5 2014 Actual Over (Under) 2014 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	4 791.1	4 131.1	660.0	(603.3)	56.7
1.1.2	Rate 1 - T-Service	589.8	490.2	99.6	(75.1)	24.5
1.1	Total Rate 1	5 380.9	4 621.3	759.6	(678.4)	81.2
1.2.1	Rate 6 - Sales	3 187.3	2 944.7	242.6	(429.9)	(187.3)
1.2.2	Rate 6 - T-Service	2 134.6	1 625.5	509.1	(220.9)	288.2
1.2	Total Rate 6	5 321.9	4 570.2	751.7	(650.8)	100.9
1.3.1	Rate 9 - Sales	0.5	0.5	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.1	0.1	0.0	0.0	0.0
1.3	Total Rate 9	0.6	0.6	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	10 703.4	9 192.1	1 511.3	(1329.2)	182.1
Contract Sales						
2.1	Rate 100	3.3	0.0	3.3	0.0 **	3.3
2.2	Rate 110	87.2	92.1	(4.9)	(0.2)	(5.1)
2.3	Rate 115	1.0	0.9	0.1	0.0	0.1
2.4	Rate 135	4.6	1.2	3.4	0.0	3.4
2.5	Rate 145	19.1	22.0	(2.9)	(0.7)	(3.6)
2.6	Rate 170	37.9	37.3	0.6	(0.9)	(0.3)
2.7	Rate 200	183.2	164.9	18.3	(11.4)	6.9
2.	Total Contract Sales	336.3	318.4	17.9	(13.2)	4.7
Contract T-Service						
3.1	Rate 100	1.1	0.0	1.1	0.0 **	1.1
3.2	Rate 110	441.2	525.6	(84.4)	(2.0)	(86.4)
3.3	Rate 115	538.4	470.1	68.3	(0.6)	67.7
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	58.1	55.3	2.8	0.0	2.8
3.6	Rate 145	122.6	142.0	(19.4)	(3.3)	(22.7)
3.7	Rate 170	417.0	425.6	(8.6)	(11.5)	(20.1)
3.8	Rate 300	38.4	30.0	8.4	0.0	8.4
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 616.8	1 648.6	(31.8)	(17.4)	(49.2)
4.	Total Contract Sales & T-Service	1 953.1	1 967.0	(13.9)	(30.6)	(44.5)
5.	Total	12 656.5	11 159.1	1 497.4	(1359.8)	137.6

*Note: Weather normalization adjustments have been made to the 2014 Actual utilizing the 2014 Board Approved Budget Degree Days in order to place the results on a comparable basis.

** Less than 50,000 m^3

The principal reasons for the variances contributing to the weather normalized increase of 137.6 10^6m^3 in the 2014 Actual over the 2014 Board Approved Budget are as follows:

1. The volumetric increase of 81.2 10^6m^3 in Rate 1 was due to a favourable customer variance of 2.5 10^6m^3 and higher average use per customer totalling 78.7 10^6m^3;

2. The volumetric increase of 100.9 10^6m^3 in Rate 6 was due to a higher average use per customer totaling 40.1 10^6m^3 and a favourable customer variance of 62.9 10^6m^3; partially offset by net customer migration to Contract Sales and T-Service of 2.1 10^6m^3;

3. The volumetric decrease for Contract Sales and T-Service of 44.5 10^6m^3 was due to decrease in the industrial sector and the commercial sector of 53.4 10^6m^3; partially offset by the increases of the apartment sector of 2.0 10^6m^3 and Rate 200 of 6.9 10^6m^3.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2014 HISTORICAL YEAR AND 2014 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2014 Actual	Col. 2 2014 Board Approved Budget	Col. 3 2014 Actual Over (Under) 2014 Budget (1-2)	Col. 4 2014* Adjustments	Col. 5 2014 Actual Over (Under) 2014 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 621.2	1 382.8	238.4	(153.3)	85.1
1.1.2	Rate 1 - T-Service	108.7	88.1	20.6	(6.4)	14.2
1.1	Total Rate 1	1 729.9	1 470.9	259.0	(159.7)	99.3
1.2.1	Rate 6 - Sales	891.1	764.0	127.1	(98.6)	28.5
1.2.2	Rate 6 - T-Service	154.7	111.8	42.9	(12.6)	30.3
1.2	Total Rate 6	1 045.8	875.8	170.0	(111.2)	58.8
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	2 775.9	2 346.9	429.0	(270.9)	158.1
Contract Sales						
2.1	Rate 100	0.7	0.0	0.7	0.0 **	0.7
2.2	Rate 110	19.2	17.6	1.6	0.0 **	1.6
2.3	Rate 115	0.2	0.2	0.0	0.0	0.0
2.4	Rate 135	1.1	0.2	0.9	0.0	0.9
2.5	Rate 145	4.2	4.1	0.1	0.1	0.2
2.6	Rate 170	7.9	6.2	1.7	0.3	2.0
2.7	Rate 200	31.2	25.2	6.0	(1.6)	4.4
2.	Total Contract Sales	64.5	53.5	11.0	(1.2)	9.8
Contract T-Service						
3.1	Rate 100	0.2	0.0	0.2	0.0 **	0.2
3.2	Rate 110	14.2	13.9	0.3	0.0 **	0.3
3.3	Rate 115	7.1	6.0	1.1	0.0 **	1.1
3.4	Rate 125	11.0	9.7	1.3	0.0 ***	1.3
3.5	Rate 135	2.0	1.5	0.5	0.0	0.5
3.6	Rate 145	4.0	3.3	0.7	0.0 **	0.7
3.7	Rate 170	7.9	(0.6)	8.5	0.1	8.6
3.8	Rate 300	0.1	0.2	(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	46.9	34.0	12.9	0.1	13.0
4.	Total Contract Sales & T-Service	111.4	87.5	23.9	(1.1)	22.8
5.	Total	2 887.3	2 434.4	452.9	(272.0)	180.9

* Note: Weather normalization adjustments have been made to the 2014 Actuals utilizing the 2014 Board Approved Budget degree days in order to place the two years on a comparable basis. Please refer to Exhibit B, Tab 3, Schedule 2, Page 2, for the corresponding volumetric adjustments.

** Less than $50,000

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

1. Gas sales and transportation of gas revenues for the 2014 Test Year Budget were developed on the basis of EB-2012-0459 rates.

2. The principal reasons for the variances contributing to the increase of $452.9 million in the 2014 Actual under the 2014 Budget are as follows:

3. <u>Gas Sales - Increase of $376.5 Million</u>

   The increase in gas sales revenue was mainly due to higher volume than budgeted and higher actual commodity charges than budgeted

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

4. <u>Transportation of Gas - Increase of $76.4 Million</u>

   The increase in T-service revenue was mainly due to higher volume than budgeted in general service; partially offset by lower volume than budgeted in contract market

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2014 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	1 693 438	4 791.1	1 621.2	
1.1.2	Rate 1 - T-Service	207 769	589.8	108.7	
1.1	Total Rate 1	1 901 207	5 380.9	1 729.9	
1.2.1	Rate 6 - Sales	137 895	3 187.3	891.1	
1.2.2	Rate 6 - T-Service	24 334	2 134.6	154.7	
1.2	Total Rate 6	162 229	5 321.9	1 045.8	
1.3.1	Rate 9 - Sales	6	0.5	0.2	
1.3.2	Rate 9 - T-Service	1	0.1	0.0	**
1.3	Total Rate 9	7	0.6	0.2	
1.	Total General Service Sales & T-Service	2 063 443	10 703.4	2 775.9	
Contract Sales					
2.1	Rate 100	1	3.3	0.7	
2.2	Rate 110	35	87.2	19.2	
2.3	Rate 115	1	1.0	0.2	
2.4	Rate 135	5	4.6	1.1	
2.5	Rate 145	12	19.1	4.2	
2.6	Rate 170	5	37.9	7.9	
2.7	Rate 200	1	183.2	31.2	
2.	Total Contract Sales	60	336.3	64.5	
Contract T-Service					
3.1	Rate 100	1	1.1	0.2	
3.2	Rate 110	156	441.2	14.2	
3.3	Rate 115	29	538.4	7.1	
3.4	Rate 125	5	0.0 *	11.0	
3.5	Rate 135	38	58.1	2.0	
3.6	Rate 145	74	122.6	4.0	
3.7	Rate 170	29	417.0	7.9	
3.8	Rate 300	2	38.4	0.1	
3.9	Rate 315	0	0.0	0.4	
3.	Total Contract T-Service	334	1 616.8	46.9	
4.	Total Contract Sales & T-Service	394	1 953.1	111.4	
5.	Total	2 063 837	12 656.5	2 887.3	

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

DETAILS OF OTHER REVENUE AND OTHER INCOME
2014 ACTUAL AND 2014 BOARD APPROVED

		Col. 1	Col. 2	Col. 3	
Item No.		2014 Actual ($Millions)	2014 Board Approved Budget ($Millions)	2014 Actual Over/(Under) 2014 Board Approved ($Millions)	
1.1	Service Charges & DPAC	12.4	12.1	0.3	
1.2	Rental Revenue - NGV Program	0.5	0.6	(0.1)	
1.3	Late Payment Penalties	13.1	10.1	3.0	*
1.4	Dow Moore Recovery	0.2	0.3	(0.1)	
1.5	Transactional Services (net)	12.0	12.0	-	
1.6	Miscellaneous and Other Income	0.3	2.3	(2.0)	**
1.7	Open Bill Revenue	5.4	5.4	-	
1.8	Total Other Revenue	43.9	42.8	1.1	

Notes:
* Late Payment Penalties are $3.0m over budget due to higher customer bills caused by the colder winter and higher price of gas.
**Miscellaneous and Other Income is ($2.0m) under budget. The budget amount reflects the EB-2012-0459 decision on Other Revenue which increased the Company's forecast of Other Revenue by $2.2m. This increase was not allocated to any specific item, and there were no actual revenue amounts forecast. The Company did achieve $0.3m in Miscellaneous Other Income, leaving a variance of ($2.0m).

Witnesses: R. Small
L. Stickles

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

Line No.		Col. 1 Utility Costs and Expenses ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Costs and Expenses ($Millions)
1.	Gas costs	1,815.5	(170.6)	1,644.9
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	408.0	-	408.0
3.	Depreciation and amortization expense	255.9	-	255.9
4.	Fixed financing costs	2.3	-	2.3
5.	Municipal and other taxes	40.5	-	40.5
6.	Operating costs	2,522.2	(170.6)	2,351.6
7.	Income tax expense			6.1
8.	Cost of service			2,357.7

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2014 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	(170.6)	Gas Costs
		Adjustment required to gas costs to reflect normal weather.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2014 ACTUAL

Line No.		Col. 1 Federal	Col. 2 Provincial	Col. 3 Combined
		($Millions)	($Millions)	($Millions)
1.	Utility income before income taxes	334.7	334.7	
	Add			
2.	Depreciation and amortization	255.9	255.9	
3.	Accrual based pension and OPEB costs	37.3	37.3	
4.	Other non-deductible items	0.7	0.7	
5.	Total Add Back	293.9	293.9	
6.	Sub-total	628.6	628.6	
	Deduct			
7.	Capital cost allowance	256.0	256.0	
8.	Items capitalized for regulatory purposes	57.4	57.4	
9.	Deduction for "grossed up" Part VI.1 tax	3.4	3.4	
10.	Amortization of share/debenture issue expense	1.3	1.3	
11.	Amortization of cumulative eligible capital	0.5	0.5	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Site restoration cost adjustment	96.8	96.8	
14.	Cash based pension and OPEB costs	43.9	43.9	
15.	Other deductible items	0.9	0.9	
16.	Total Deduction	460.3	460.3	
17.	Taxable income	168.3	168.3	
18.	Income tax rates	15.00%	11.50%	
19.	Provision	25.2	19.4	44.6
20.	Part VI.1 tax			1.0
21.	Total taxes excluding interest shield			45.6
	Tax shield on interest expense			
22.	Rate base	4,701.3		
23.	Return component of debt	3.17%		
24.	Interest expense	149.2		
25.	Combined tax rate	26.500%		
26.	Income tax credit			(39.5)
27.	Total utility income taxes			6.1

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

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	2,009.6	(194.1)	1,815.5
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	431.9	(23.9)	408.0
3.	Depreciation	256.7	(23.3)	233.4
4.	Amortization	22.5	-	22.5
5.	Depreciation and amortization	279.2	(23.3)	255.9
6.	Fixed financing costs	2.3	-	2.3
7.	Municipal and other taxes	40.7	(0.2)	40.5
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	40.7	(0.2)	40.5
10.	Interest on long-term debt	148.4	(148.4)	-
11.	Amortization of preference share issue costs and debt discount and expense	0.9	(0.9)	-
12.	Interest and financing amortization	149.3	(149.3)	-
13.	Interest on short-term debt	11.2	(11.2)	-
14.	Interest due affiliates	28.4	(28.4)	-
15.	Other interest expense	39.6	(39.6)	-
16.	Total operating costs	2,952.6	(430.4)	2,522.2
17.	Current taxes	1.9	(1.9)	-
18.	Deferred taxes	3.2	(3.2)	-
19.	Income tax expense	5.1	(5.1)	-
20.	Cost of service	2,957.7	(435.5)	2,522.2

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2014 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	(194.1)	Gas costs	
		US GAAP adjustment elimination, deferral & variance clearance recognition.	
2.	(23.9)	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.	0.9
		To eliminate donations (EBRO 490).	(1.2)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.6)
		US GAAP adjustment elimination, deferral & variance clearance recognition.	(3.4)
		To eliminate the correction of the 2013 DSMVA amount recorded in 2014.	0.1
		To eliminate Corporate Cost allocations above RCAM amount.	(6.7)
		To eliminate earnings sharing recorded in the financial statements.	(12.0)
			(23.9)
3.	(23.3)	Depreciation expense	
		Removal of depreciation on disallowed Mississauga Southern Link amounts (EBRO 473 & 479).	(0.1)
		Removal of depreciation related to shared assets (RP-2002-0133).	(0.7)
		To eliminate the amortization of PPD	(22.5)
			(23.3)
7.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2014 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
10.	(148.4)	Interest on long-term debt	
		Expense of capital.	
11.	(0.9)	Amortization of preference share issue costs and debt discount and expense	
		Expense of capital.	
13.	(11.2)	Interest on short-term debt	
		Expense of capital.	
14.	(28.4)	Interest due affiliates	
		To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).	(26.8)
		To eliminate, as an expense of capital, interest on the $300 million revolving credit facility from Enbridge Inc.	(1.6)
			(28.4)
17.	(1.9)	Income taxes - current	
		Income tax expense related to corporate earnings.	
18.	(3.2)	Income taxes - deferred	
		Income tax expense related to corporate earnings.	

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2014 ACTUAL

Capital Cost Allowance - Federal

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2014	UCC Carry Forward
1	1,788,040,222	-	-	-	4.00%	(71,521,609)	1,716,518,613
51	1,550,716,086	400,066,048	300,000	200,183,024	6.00%	(105,053,947)	1,846,028,187
2	112,509,950	-	(534,232)	(267,116)	6.00%	(6,734,570)	105,241,148
6	11,768	-	-	-	10.00%	(1,177)	10,591
8	10,416,048	3,041,638	-	1,520,819	20.00%	(2,387,373)	11,070,313
10	17,330,009	15,236,656	(382,375)	7,427,141	30.00%	(7,427,145)	24,757,145
12	26,695,769	41,319,861	-	20,659,931	100.00%	(47,355,700)	20,659,931
17	29,794	-	-	-	8.00%	(2,384)	27,411
38	2,389,419	2,615,340	(61,000)	1,277,170	30.00%	(1,099,977)	3,843,782
41	27,130,901	6,415,085	-	3,207,543	25.00%	(7,584,611)	25,961,375
13	2,017,224	752,498	-	376,249	-	(647,400)	2,122,322
3	224,883	-	-	-	5.00%	(11,244)	213,639
45	269,361	-	-	-	45.00%	(121,213)	148,149
50	10,551,920	3,721,429	-	1,860,715	55.00%	(6,826,949)	7,446,400
52	-	-	-	-	100.00%	-	-
Total	3,548,333,354	473,168,555	(677,607)	236,245,474		(256,775,297)	3,764,049,005

Non-utility and shared asset eliminations	796,529
Utility Federal CCA	(255,978,768)

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 F2014	UCC Carry Forward
1	1,788,040,222	-	-	-	4.00%	(71,521,609)	1,716,518,613
51	1,550,716,086	400,066,048	300,000	200,183,024	6.00%	(105,053,947)	1,846,028,187
2	112,509,950	-	(534,232)	(267,116)	6.00%	(6,734,570)	105,241,148
6	11,768	-	-	-	10.00%	(1,177)	10,591
8	10,416,048	3,041,638	-	1,520,819	20.00%	(2,387,373)	11,070,313
10	17,330,009	15,236,656	(382,375)	7,427,141	30.00%	(7,427,145)	24,757,145
12	26,695,769	41,319,861	-	20,659,931	100.00%	(47,355,700)	20,659,931
17	29,794	-	-	-	8.00%	(2,384)	27,411
38	2,389,419	2,615,340	(61,000)	1,277,170	30.00%	(1,099,977)	3,843,782
41	27,130,901	6,415,085	-	3,207,543	25.00%	(7,584,611)	25,961,375
13	2,017,224	752,498	-	376,249	-	(647,400)	2,122,322
3	224,883	-	-	-	5.00%	(11,244)	213,639
45	269,361	-	-	-	45.00%	(121,213)	148,149
50	10,551,920	3,721,429	-	1,860,715	55.00%	(6,826,949)	7,446,400
52	-	-	-	-	100.00%	-	-
Total	3,548,333,354	473,168,555	(677,607)	236,245,474		(256,775,297)	3,764,049,005

Non-utility and shared asset eliminations	796,529
Utility Provincial CCA and UCC	(255,978,768)

OPERATING AND MAINTENANCE EXPENSE

Line No.	Particulars ($000's)	Col. 1 Actuals 2014	Col. 2 2014 Board Approved	Col. 3 Difference
1	Operations (including Pipeline Integrity and Engineering)	$ 102,534	$ 104,804	$ 2,270
2	Human Resources and Facilities	24,658	21,972	(2,686)
3	Employee Benefits	26,541	25,756	(785)
4	Short Term Incentive Program	23,018	21,156	(1,862)
5	Information Technology	27,902	26,387	(1,514)
6	Finance	8,689	11,717	3,028
7	Regulatory, Public and Government Affairs	20,936	22,589	1,653
8	Provision for Uncollectibles (Bad Debts)	12,147	9,500	(2,647)
9	Customer Care (Exclude CC/CIS and Bad Debts)	2,038	2,334	296
10	Business Development & Customer Strategy (excluding DSM)	3,835	6,185	2,350
11	Legal and Corporate Security	4,818	5,253	435
12	Energy Supply and Policy	4,179	4,243	64
13	Non Departmental Expenses	3,998	3,589	(410)
14	Capitalization (A&G)	(37,010)	(35,500)	1,510
15	Interest on Security Deposit	880	1,313	433
16	Regulatory Eliminations	(3,686)	(3,276)	410
17	Other O&M Subtotal	$ 225,477	$ 228,022	$ 2,546
18	Customer Care/CIS Service Charges (Net of rate smoothing adj.)	79,633	89,704	10,071
19	Pensions and OPEB	37,248	37,248	(0)
20	Corporate Allocations (including direct costs)	40,294	44,977	4,683
21	Demand Side Management Programs (DSM)	32,159	32,159	(0)
22	Conservation Services	1,718	1,976	258
23	Total Net Utility O&M Expense before Eliminations	416,529	434,086	17,557
	Additional Regulatory Eliminations			
24	To eliminate Corporate Cost Allocations above RCAM	(6,677)	(9,695)	(3,018)
25	To eliminate Conservation Services and Overheads	(1,718)	(1,976)	(258)
26	Total Eliminations	(8,395)	(11,671)	(3,276)
27	Total Net Utility O&M Expense	$ 408,134	$ 422,415	$ 14,281

Notes:
1) Departmental O&M costs are net of capitalization, non-utility,and other utility adjustments.
2) 2014 Actuals revised to reflect the organizational structure reflected in the Custom IR filing

Witnesses: A. Patel
L. Stickles

EXPLANATION OF MAJOR CHANGES
ACTUAL 2014 O&M EXPENSES COMPARED TO OEB APPROVED 2014 O&M EXPENSES

The 2014 Actual Utility O&M was $408.2 million, which was $14.3 million lower than the 2014 Board-approved Utility O&M. The decrease was driven by the following areas:

Line No:

1. Operations decreased by $2.3 million mostly due to lower in-line inspection activity, higher third party damage recoveries and a different level of work within O&M versus capital activities. These were partially offset by higher locate costs due to Bill 8, and higher vital main standby costs.

2. Human Resources and Facilities increased by $2.7 million primarily as a result of staff reductions and therefore higher severance costs.

4. Short Term Incentive Program increased by $1.9 million. The Company achieved high results on two of the three factors that STIP is measured on.

5. Information Technology increased by $1.5 million primarily due to a shift in work load from more capital-related projects to more support-related projects. In addition, there were higher software maintenance costs from the Mobility system being put into use.

6. Finance decreased $3.0 million due to one-time adjustments required to correct for certain balance sheet accounts (primarily related to an insurance reserve no longer required, and an accrued liability for contractor costs no longer required), staff reductions and hiring delays, and staff secondments.

7. Regulatory, Public and Government Affairs decreased $1.7 million from lower customer communication outreach programs, lower sponsorship costs, and hiring delays. This was offset by higher rate hearing costs from the Custom IR proceeding.

Witnesses: A. Patel
L. Stickles

8. Provision for Uncollectibles increased $2.6 million because of higher sales and billings throughout the year.

10. Business Development and Customer Strategy decreased $2.3 million from a reduction in program costs, a decrease in staff levels and staff lags to balance work activity, and a reduction in employee related costs.

14. Capitalization (Administration and General) increased $1.5 million. This is from higher support costs related to the GTA project.

18. Customer Care/CIS Service Charges decreased $10.1 million. This is primarily due to lower billing and postage costs as a result of higher penetration in e-billing, lower system and software licensing costs, and lower CIS IT support costs.

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

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
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,705.7	57.55	5.41	3.113	146.4
2.	Short-Term Debt	203.1	4.32	1.38	0.060	2.8
3.		2,908.8	61.87		3.173	
4.	Preference Shares	100.0	2.13	2.40	0.051	2.4
						151.6
5.	Common Equity	1,692.5	36.00	9.36	3.370	
6.		4,701.3	100.00		6.594	
7.	Rate Base	($Millions)			4,701.3	
8.	Utility Income	($Millions)			328.6	
9.	Indicated Rate of Return				6.990	
10.	Sufficiency in Rate of Return				0.396	
11.	Net Sufficiency	($Millions)			18.6	
12.	Gross Sufficiency	($Millions)			25.3	
13.	Revenue at Existing Rates	($Millions)			2,642.4	
14.	Allowed Revenue	($Millions)			2,617.1	
15.	Gross Revenue Sufficiency	($Millions)			25.3	
	Common Equity					
16.	Allowed Rate of Return				9.360	
17.	Earnings on Common Equity				10.461	
18.	Sufficiency in Common Equity Return				1.101	

Witness: R. Small

UTILITY INCOME (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

Line No.		Col. 1 Utility Income ($Millions)
1.	Gas sales	2,360.6
2.	Transportation of gas	280.0
3.	Transmission, compression and storage revenue	1.8
4.	Other operating revenue	43.6
5.	Interest and property rental	-
6.	Other income	0.3
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,686.3
8.	Gas costs	1,644.9
9.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	408.0
10.	Depreciation and amortization expense	255.9
11.	Fixed financing costs	2.3
12.	Municipal and other taxes	40.5
13.	Interest and financing amortization expense	-
14.	Other interest expense	-
15.	Cost of service (Ex. B-4-1-pg.1)	2,351.6
16.	Utility income before income taxes	334.7
17.	Income tax expense (Ex. B-4-1-pg.3)	6.1
18.	Utility income	328.6

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2014 ACTUAL

Line No.		Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	2,691.2		145.7
2.	Unamortized Finance Costs	14.5		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,705.7		145.7
5.	Calculated Cost Rate		5.41%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.38%	
	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 Formula ROE		9.36%	

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2014 ACTUAL

Line No.	Coupon Rate	Maturity Date	Col. 1 Average of Monthly Averages Principal ($Millions)	Col. 2 Effective Cost Rate	Col. 3 Carrying Cost ($Millions)
Medium Term Notes					
1.	8.85%	October 2, 2025	20.0	8.970%	1.8
2.	7.60%	October 29, 2026	100.0	8.086%	8.1
3.	6.65%	November 3, 2027	100.0	6.711%	6.7
4.	6.10%	May 19, 2028	100.0	6.161%	6.2
5.	6.05%	July 5, 2023	100.0	6.383%	6.4
6.	6.90%	November 15, 2032	150.0	6.950%	10.4
7.	6.16%	December 16, 2033	150.0	6.180%	9.3
8.	5.16%	September 24, 2014	141.7	5.610%	7.9
9.	5.21%	February 25, 2036	300.0	5.183%	15.5
10.	4.77%	December 17, 2021	175.0	5.310%	9.3
11.	5.16%	December 4, 2017	200.0	5.220%	10.4
12.	5.57%	January 29, 2014	8.3	5.660%	0.5
13.	4.04%	November 23, 2020	200.0	5.209%	10.4
14.	4.95%	November 22, 2050	200.0	4.990%	10.0
15.	4.95%	November 22, 2050	100.0	4.731%	4.7
16.	4.04%	November 23, 2020	200.0	2.801%	5.6
17.	4.50%	November 23, 2043	200.0	4.198%	8.4
18.	1.85%	April 24, 2017	-	1.967%	- [1]
19.	3.15%	August 22, 2024	80.6	3.241%	2.6
20.	4.00%	August 22, 2044	80.6	3.889%	3.1
21.			2,606.2		137.3
Long-Term Debentures					
22.	9.85%	December 2, 2024	85.0	9.910%	8.4
23.			85.0		8.4
24.	Total Term Debt		2,691.2		145.7

Notes:

1. Enbridge's April 2014 issuance of a $300 million three-year note has been removed

UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2014 ACTUAL

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	(12.0)
2.	January 31	(12.1)
3.	February	(12.2)
4.	March	(12.3)
5.	April	(12.3)
6.	May	(12.4)
7.	June	(12.5)
8.	July	(12.6)
9.	August	(18.0)
10.	September	(18.0)
11.	October	(18.1)
12.	November	(18.1)
13.	December	(17.9)
14.	Average of Monthly Averages	(14.5)

DEFERRAL & VARIANCE ACCOUNTS
REQUESTED FOR CLEARANCE OCTOBER 1, 2015

1. The Company requests approval for clearance of the Deferral and Variance Account balances shown in the Table on page 3, Columns 3 & 4 of this Exhibit, commencing October 1, 2015. 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. The 2014 DSM related accounts will be brought forward for review and clearance through a separate application.

3. Within the remainder of the Exhibit C, Tab 1 evidence, Enbridge has provided explanatory information for each of the accounts for which clearance is sought. Some of these clearance amounts have been approved in another proceeding, and some of the accounts have a previously established process which has been followed in determining the account balance.

4. The interest on the principal balances in the Deferral and Variance Accounts has been calculated using the Board's prescribed interest rates for deferral and variance accounts, including the April 1, 2015 prescribed rate. 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. Note that the CCCISRSDA interest has been calculated using a fixed rate of 1.47%, as stipulated in the EB-2011-0226 CC/CIS Settlement Agreement.

5. The Company notes that at this time it is not requesting clearance of the balances which were recorded within the 2014 Manufactured Gas Plant Deferral Account (“MGPDA”), or the 2014 Constant Dollar Net Salvage Adjustment Deferral Account (“CDNSADA”). The December 31, 2014 MGPDA principal and interest balances were transferred to corresponding 2015 accounts in accordance with the 2015 account descriptions approved within EB-2014-0276. Clearance of amounts recorded in the MGPDA will be requested in a future proceeding. The December 31, 2014 CDNSADA principal balance was transferred to the corresponding 2015 account in accordance with the account scope and methodology that was approved within EB-2012-0459, and as further documented within the 2015 account description approved within EB-2014-0276. Any balance recorded in the CDNSADA at the end of 2018 will be requested for clearance in a post 2018 true-up.

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at April 30, 2015 Principal ($000's)	Col. 2 Actual at April 30, 2015 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2015 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2015 Interest ($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2014 DSMVA	352.5	1.6	-	-	1
2.	Deferred Rebate Account	2014 DRA	(3,167.6)	(10.7)	(3,167.6)	(25.2)	2
3.	Gas Distribution Access Rule Impact D/A	2014 GDARIDA	-	-	152.7	-	3
4.	Average Use True-Up V/A	2014 AUTUVA	(4,894.0)	(22.5)	(4,894.0)	(45.0)	4
5.	Earnings Sharing Mechanism Deferral Account	2014 ESMDA	(12,650.0)	(55.7)	(12,650.0)	(113.7)	5
6.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	34.0	-	52.0	6
7.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	122.1	-	150.6	6
8.	Transition Impact of Accounting Changes D/A	2015 TIACDA	79,844.4	-	4,435.8	-	7
9.	Post-Retirement True-Up V/A	2014 PTUVA	(6,220.6)	(28.6)	(5,000.0)	(45.9)	8
10.	Credit Final Bill D/A	2015 CFBDA	-	-	(5,517.6)	(20.4)	9
11.	Manufactured Gas Plant D/A	2015 MGPDA	426.4	30.0	-	-	10
12.	Constant Dollar Net Salvage Adjustment D/A	2015 CDNSADA	44,333.4	-	-	-	11
13.	Total non commodity Related Accounts		105,586.4	70.2	(26,640.7)	(47.6)	
	Commodity Related Accounts						
14.	Transactional Services D/A	2014 TSDA	(1,256.7)	(5.6)	(1,256.7)	(11.6)	12
15.	Storage and Transportation D/A	2014 S&TDA	(1,147.6)	(10.9)	(1,147.6)	(16.4)	12
16.	Unaccounted for Gas V/A	2014 UAFVA	11,917.1	53.4	11,917.1	108.5	13
17.	Design Day Criteria Transportation D/A	2014 DDCTDA	12,839.3	112.3	12,839.3	171.3	14
18.	Unabsorbed Demand Cost D/A	2014 UDCDA	13,526.2	119.0	13,526.2	181.0	14
19.	Total commodity related accounts		35,878.3	268.2	35,878.3	432.8	
20.	Total Deferral and Variance Accounts		141,464.7	338.4	9,237.6	385.2	

Notes:

1. Clearance of the 2014 DSMVA will be requested through a separate application at a later date.
2. DRA evidence is found at Exhibit C, Tab 1, Schedule 8.
3. The forecast clearance amount associated with the 2014 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 7.
4. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
5. Evidence within the B-series of exhibits provides details of Enbridge's 2014 utility results and 2014 earnings sharing calculation.
6. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 10.
7. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 9.
8. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 6.
9. CFBDA evidence is found at Exhibit C, Tab 1, Schedule 11.
10. Clearance of the balance that was recorded in 2014 MGPDA is not being requested at this time. As was indicated in the EB-2014-0276 proceeding, the balance in the 2014 MGPDA was transferred to the 2015 MGPDA.
11. Clearance of the balance that was recorded in 2014 CDNSADA is not being requested at this time. In accordance with the scope of the account that was approved in EB-2012-0459, and as was also indicated in EB-2014-0276, the balance was transferred to the 2015 CDNSADA. The cumulative balance at the end of each year will be transferred to the following year's CDNSADA. At the end of 2018, any residual balance will be requested for clearance in a post 2018 true-up.
12. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 3.
13. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 4.
14. DDCTDA and UDCDA evidence is found at Exhibit C, Tab 1, Schedule 2.

Witness: R. Small

2014 UNABSORBED DEMAND CHARGE DEFERRAL ACCOUNT AND 2014 DESIGN DAY CRITERIA TRANSPORTATION DEFERRAL ACCOUNT REQUESTED FOR CLEARANCE OCTOBER 1, 2015

2014 Design Day Criteria Transportation Deferral Account (2014 DDCTDA) and 2014 Unabsorbed Demand Charges Deferral Account (2014 UDCDA)

The purpose of the 2014 DDCTDA and the 2014 UDCDA is to record the actual cost consequences of unutilized contracted transportation capacity contracted by the Company to meet its Peak Day requirements in 2014. A consequence of contracting for incremental long haul capacity is the possibility of unabsorbed demand charges.

Background

1. During the summer of 2013 Enbridge prepared its original 2014 supply portfolio based upon the assumption that it would acquire STFT at a cost equivalent to the TCPL FT toll. Included within the original 2014 supply portfolio was a total of 257,500 GJ of STFT service (Empress to CDA) to assist in meeting the peak day requirement, as seen at Exhibit D1, Tab 2, Schedule 2, page 1 (EB-2012-0459).

2. In March of 2013 the NEB decision (RH-003-2011) approved new tolls which included new pricing discretion for discretionary services including STFT. During the summer of 2013 it started to become clear that TCPL would use that pricing discretion to incent shippers who needed winter seasonal services to instead purchase annual FT. For example, in the summer of 2013 TCPL was asking for a minimum bid floor price for STFT equal to 260% of current FT toll price for a November 1st to March 31st (151 days) service making it cost approximately 108% of annual FT service cost.

Witnesses: J. LeBlanc
D. Small

3. In the summer of 2013, Enbridge looked to contract for 2013/14 winter capacity to meet the system reliability agreement requirements pertaining to the replacement of the Dawn to CDA short haul capacity that is assigned to agents of mass market customers. On July 12, 2013 Enbridge sent a letter to the Board and to interested parties informing them of Enbridge's intent to acquire FT transportation, instead of five months of STFT, because of an estimated annual savings of approximately $4.5 million. This projected savings was based upon the minimum floor bid price for winter STFT at that time which was posted as 290% of the FT toll. Enbridge subsequently contracted for 38,000 GJ/day of FT capacity from November 1, 2013 to October 31, 2014.

4. Subsequent to the filing of that letter the Company continued to look for alternatives to meeting the outstanding peak day requirement. Enbridge was able to enter into an arrangement with a third party to provide 50,000 GJ of capacity to the CDA for the winter period at a price that is less than the updated STFT toll as well as the annual FT toll.

5. This left a remaining 170,000 GJ/day of STFT capacity, of the planned 257,500 GJ's, still to be acquired by the Company to meet its peak day obligations. Enbridge sent a second letter to the Board and interested parties dated August 30th, 2013 identifying the various options available to Enbridge. The viable options were to contract for 5 months of STFT at a toll equivalent to 260% of the then current FT toll or to contract for 1 year of FT long haul capacity. Based upon the information available at the time the Company determined that the preferred option would be to acquire 170,000 GJ/day of FT capacity which would be at a lower overall annual cost for ratepayers than the STFT as originally planned.

6. Further, as noted in the August 2013 letter, based on budgeted demand it was forecast that there would be unutilized capacity during the winter months regardless of whether Enbridge contracted for STFT or FT capacity. That was due to the fact that while the capacity was required to meet peak day there would be excess capacity on the average winter day. Additionally it was noted that, although less costly for ratepayers overall and therefore the best choice available, contracting for a full year of FT capacity would result in forecasted unutilized capacity in the summer of 2014 which was not the case in prior years when the Company was able to contract for Winter STFT.

7. Although cheaper than the alternative STFT and the least expensive option available, FT was more expensive than what would have been used historically because of the costs associated with Unutilized Demand Charges ("UDC") forecast to be incurred in the summer of 2014. The Company recognized concerns that were being raised by Intervenors regarding the gas cost impacts of contracting for FT and invited Intervenors to attend a meeting on October 2, 2013. At that meeting the Company presented an update 2014 gas supply plan and answered questions that the Intervenors had as well as discussed possibilities for the recovery of such costs.

8. In early November 2013, the Company reached a Settlement Agreement with parties to include in the 2014 DDCTDA the cost consequences of unutilized transportation costs associated with the change in the Peak Gas Design Day Criteria approved by the Board in EB-2011-0354, which was to be phased in equally over the 2013 and 2014 fiscal years and to the establishment of the 2014 UDCDA to capture the cost consequences of unutilized capacity in excess of the amounts recorded in the 2014 DDCTDA.

Witnesses: J. LeBlanc
D. Small

9. As part of the Settlement Agreement, the Company committed to use best efforts to mitigate what it could of the forecasted unutilized transportation cost while it executed its gas supply plan. Among the strategies committed to by the Company was that during the year if the Company required additional capacity for either satisfying customer demand and/or filling storage then this FT capacity would be used to the extent possible to meet that requirement and thus eliminate the associated unutilized transportation cost. The Company also committed to releasing the remaining unneeded capacity and crediting the proceeds, in their entirety, to offset the unutilized transportation costs.

10. As part of the Settlement Agreement, the Company also agreed to file, on a monthly basis, a report identifying the amount of unutilized capacity and the associated costs of that capacity as well as the capacity released to third parties and the amount of revenue received from those releases.

Utilization of capacity in 2014

11. The extreme weather experienced in the winter of 2014 had a doubling effect in terms of reducing actual unutilized demand incurred. The Company was able to fully utilize its contracted long haul TCPL capacity (including forecast UDC) during the months of January to March to assist in meeting demand. The reliance on storage withdrawals throughout the winter also left the Company with a greater requirement for injection volumes over the summer of 2014.

12. Gas Supply and Gas Storage personnel met regularly to develop, make decisions on and monitor outcomes of the Company's storage injection strategy. These discussions included consideration of: a) Operational constraints (maintenance,

construction and planned outages), b) Demand constraints, c) Risk of mechanical failure and d) Impact of direct purchase customer make-up requirements. Among other considerations was the fact that in July of 2013 TransCanada had made changes to the way it operated its system which reduced the pressure available to inject gas into storage and that 2014 was the first full year working with those reduced pressures which would impact the Company's planned summer injection capabilities. The injection strategy also included discussions regarding the management of the forecasted unutilized long haul capacity.

13. From an unutilized demand charge/capacity perspective, the team weighed the then current situational parameters and chose to front end load its injection schedule and as a consequence fully utilize its long haul capacity (including forecast UDC) for Utility purposes. For the months of July to October the Company released capacity that it did not otherwise need through a combination of monthly and daily releases. As the attached report illustrates, the Company experienced 20.1 PJ's of unutilized capacity which it was 100% successful in releasing to third parties. The cost of this capacity was $31.7 million and the Company was able to generate $5.3 million in revenue. The result is that there is a net UDC cost of $26.4 million to be recovered from customers - $12.9 million in the 2014 DDCTDA and $13.6 million in the 2014 UDCDA. This compares to the original forecast of $104.3 million of unutilized capacity costs to be recorded in the 2014 DDCTDA ($41.5 million) and the 2014 UDCDA ($62.8 million) as filed in EB-2012-0459, Exhibit N1, Tab 2, Schedule 1, page 4 of 19.

14. Simple interest is to be calculated on the opening monthly balance of the 2014 DDCTDA using the Board Approved EB-2006-0117 interest rate methodology.

Witnesses: J. LeBlanc
D. Small

The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

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December 31, 2014

VIA RESS and COURIER

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

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
<u>Ontario Energy Board File No. EB-2012-0459</u>

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, p. 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014. Please see the attached report for November, 2014.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2012-0459 Interested Parties

December 2014 Report

Demand	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual - Updated July	Actual August	Actual September	Actual October	Actual November	Estimate December	
PJ's	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.5	27.0	51.7	60.6	493.9

Forecasted Monetary Impacts by Delivery Area
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.6	4.5	2.9	3.2	-	-	11.2
- EDA	-	-	-	-	-	-	0.3	2.0	1.3	1.4	-	-	5.0
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.2)	(0.9)	(0.6)	(1.0)	-	-	(2.7)
Net Impact on Deferral Account	-	-	-	-	-	-	0.7	5.5	3.6	3.7	-	-	13.6
DDCTDA													
- CDA	-	-	-	-	-	-	3.5	3.6	3.5	3.0	-	-	13.6
- EDA	-	-	-	-	-	-	0.5	0.5	0.5	0.4	-	-	1.9
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.8)	(0.6)	(0.6)	(0.7)	-	-	(2.6)
Net Impact on Deferral Account	-	-	-	-	-	-	3.2	3.5	3.4	2.7	-	-	12.9

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.4	2.8	1.9	2.1	-	-	7.2
- EDA	-	-	-	-	-	-	0.2	1.2	0.8	0.9	-	-	3.1
Unutilized Capacity Released	-	-	-	-	-	-	(0.6)	(4.1)	(2.7)	(3.0)	-	-	(10.2)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
DDCTDA													
- CDA	-	-	-	-	-	-	2.2	2.3	2.3	1.9	-	-	8.7
- EDA	-	-	-	-	-	-	0.3	0.3	0.3	0.3	-	-	1.2
Unutilized Capacity Released	-	-	-	-	-	-	(2.5)	(2.6)	(2.6)	(2.2)	-	-	(9.9)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
Total													
- CDA	-	-	-	-	-	-	2.6	5.2	4.1	4.0	-	-	15.9
- EDA	-	-	-	-	-	-	0.5	1.5	1.1	1.1	-	-	4.2
Unutilized Capacity Released	-						(3.1)	(6.7)	(5.2)	(5.1)	-		
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	20.1

Degree Days													
Central Region	813.0	724.1	669.3	352.3	127.4	12.6	4.9	9.3	70.0	230.7	474.2	550.0	4,037.8
Niagara Region	758.1	679.1	637.5	330.0	137.6	14.9	5.1	5.8	69.9	203.1	439.6	526.1	3,806.8
Eastern Region	895.2	775.3	751.1	381.2	124.0	14.9	10.4	22.0	115.3	260.9	507.7	725.7	4,583.7

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	15.0	16.2	21.8	9.0	-	-	-	-	-	-	5.1	13.5	80.6

Month end Storage Capacity												
% Fill	0.39	0.19	0.14	0.20	0.35	0.49	0.75	0.87	0.97	1.00	0.94	0.78

Month end Storage Capacity Taget												
% Fill	0.47	0.24	0.06	0.07	0.20	0.36	0.56	0.75	0.92	1.00	0.95	0.78

2014 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT, 2014 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT, REQUESTED FOR CLEARANCE OCTOBER 1, 2015

2014 Storage and Transportation Deferral Account ("2014 S&TDA")

1. The purpose of the 2014 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the Company.

2. The S&TDA also records the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition the S&TDA is used to record amounts received by the Company related to deferral account dispositions of other utilities' deferral accounts.

3. The balance in the 2014 S&TDA that the Company is proposing to refund to customers is $1.15 million plus interest.

2014 Transactional Services Deferral Account ("2014 TSDA")

4. The concept of Transactional Services operates under the premise that if circumstances arise where the assets acquired by Enbridge to meet customer demand are not fully required then those assets can be made available to generate third party revenue. Transactional Services are the optimization of these assets.

5. Transactional services optimization can be grouped into two different categories – storage optimization and transportation optimization. Storage Optimization transactions typically rely on storage or the loan of gas between two points in time

at the same location (i.e., Dawn). Transportation Optimization transactions typically rely on the exchange of gas on the day between two locations.

6. Any net revenues received from Transactional Services are to be shared 90:10 between the ratepayer and the Company. The rates designed by the Company include an upfront benefit of $12 million in Transactional Services revenue that has been applied to reduce the overall costs to be collected from ratepayers. The purpose of the TSDA is to capture the difference between the total ratepayer share of Transactional Services revenue and the amount already included in rates.

7. During 2014 the Company was able to generate a total of $14.5 million in net Transactional Services revenue through a combination of Storage and Transportation Optimization. The attached schedule provides a breakdown of Transactional Services revenue by type of transaction, and sets out the details of the amount, $1.26 million proposed to be cleared through the 2014 TSDA.

8. The transactions that Enbridge entered into in 2014 contained the three elements of Transactional Services as were described in the Company's evidence in EB-2013-0046 in that they were Unplanned, the result of a Third Party Service Request and were available because of Temporarily Surplus Capacity.

Witnesses: J. LeBlanc
D. Small

2014 TRANSACTIONAL SERVICES REVENUE

Item #		$ 000's
1.0	Storage Optimization	1,703.4
2.0	Transportation Optimization	12,910.3
3.0	Transactional Serives Revenue	14,613.7
4.0	Ratepayer Portion of TS	13,152.4
5.0	Less Guarantee in Rates	12,000.0
6.1	TSDA sub-total	1,152.4
6.2	ETT Revenue - Rider H	104.4
6.0	TSDA Total	1,256.7

Witnesses: J. LeBlanc
R. Small

UNACCOUNTED-FOR GAS VARIANCE ACCOUNT

1. This evidence provides the volumetric variance underpinning the balance in the Unaccounted-For Gas Variance Account ("UAFVA"). It will describe the 2014 variance relative to historical Unaccounted-For Gas ("UAF") volumes. The Company requests that the Board approve the 2014 UAFVA balance as part of the clearance of 2014 Deferral and Variance Accounts in light of the evidence here contained.

2. Unaccounted-For Gas is the difference between natural gas delivered into the distribution system as billed by third-party transmission entities (namely, TransCanada Pipelines and Union Gas) and natural gas that is billed as consumption to over two million customers. Owing to its residual nature, UAF cannot be measured directly. UAF can arise from meter differences, operational or external factors such as line leakage, unmetered uses, and third party damages. In addition, because gas volumes are affected by temperature and pressure, measurement is made more difficult.

3. Nevertheless, the Company is committed to apply best practices and has undertaken measures to help controlling measurement variations to better manage the amount of UAF where possible. Its initiatives are detailed in a UAF study filed in 2013 (EB-2011-0354, Exhibit D2, Tab 6, Schedule 1).

4. The 2014 level of UAF was determined to be 135,380 10^3m^3 which represents 1.08% of total sendout. The variance of 57,720 10^3m^3, which is the difference between actual UAF volume and forecast UAF volume, underpins the $11.9 million account balance that is captured in the UAFVA.

Witness: M. Suarez

5. Although the root causes of UAF are generally known as noted earlier, it continues to be difficult to quantify the individual factors due to their nature. No significant factors are known to have occurred in 2014 that would have contributed to a higher UAF than recently experienced.

6. UAF has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels in 2013-2014 (Table 2). Although temperature-compensated meters are used, the Company notes that the higher levels of UAF coincide with two consecutively cold winters. Nevertheless, given the inherent volatility of UAF, the 2014 level still falls within the 95% confidence interval, bounded by (17,359) 10^3m^3 and 147,810 10^3m^3(Table 3).

7. In a similar vein, expressing UAF as a proportion of throughput, the 2014 actual proportion of 1.08% falls within the 95% confidence interval bounded by -0.15% and 1.33%. This discrepancy falls within Measurement Canada's tolerance level of +/- 1.0% and +/- 1.5% depending on meter types.

Table 2:

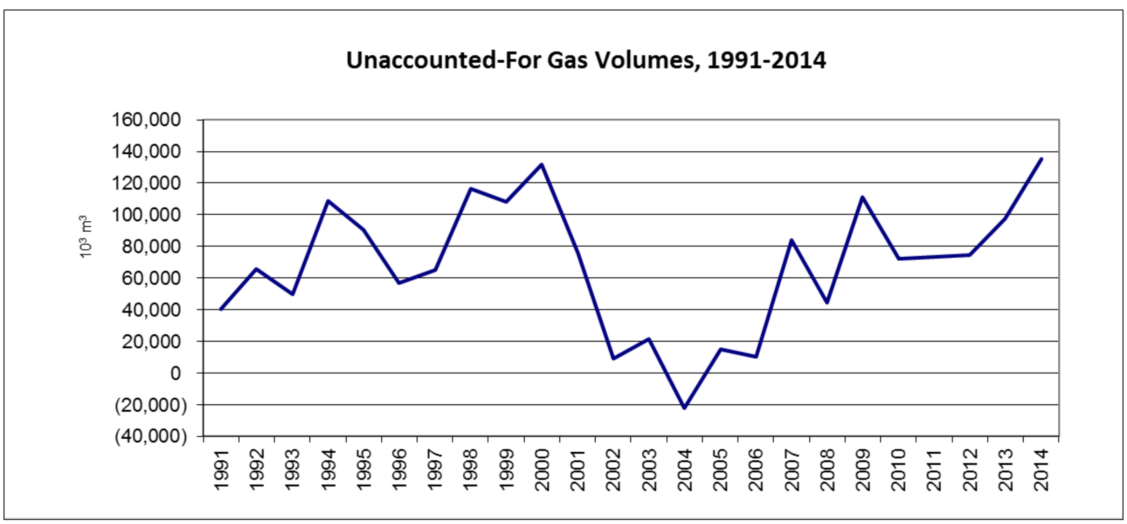

Table 3:

Col.1	*Col.2*
Calendar Year	**UAF Volumes (10^3 m^3)**
1991	40,662
1992	66,028
1993	49,782
1994	108,765
1995	90,655
1996	56,739
1997	65,228
1998	116,376
1999	108,201
2000	132,021
2001	75,606
2002	9,284
2003	21,412
2004	(22,406)
2005	14,815
2006	10,274
2007	83,823
2008	44,424
2009	110,917
2010	72,104
2011	73,355
2012	74,762
2013	97,361
2014	135,380

	1991-2013
Standard Deviation	39,819
Mean	65,225
Lower bound*	(17,359)
Upper bound*	147,810

*95% confidence interval with 22 degrees of freedom (number of observations-1)

Witness: M. Suarez

2014 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2014 Average Use True-up Variance Account (“AUTUVA”) balance.

2. Table 1 of Appendix A details the calculations that result in the amount of $4.90 million that will constitute a refund to ratepayers. The refund is attributable to actual Rate 1 (residential) and Rate 6 average uses which are higher than budget levels.

3. Higher average uses than forecast can primarily be attributable to lower actual natural gas prices and better economic conditions in 2014 than were forecast. Lower gas prices have been shown to increase residential consumption. At the same time, higher employment levels similarly support stronger economic conditions which lead to higher consumption.

4. In accordance with the 2013 Board-Approved EB-2011-0354 Settlement Agreement (Exhibit N1, Tab 1, Schedule 1, Issue DV1, which accepts evidence filed at Exhibit D, Tab 8, Schedule 1), 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 revenue impact is calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism (“LRAM”), extended by the average use volume variance per customer and the number of customers.

5. As detailed in Table 1, the calculation of the volumetric variance between forecast average use and actual normalized average use subtracts the volumetric impact of Demand Side Management ("DSM") programs in the year. As has been the case in previous applications, since the audited actual volume savings of 2014 DSM activities will not be available until later in 2015, the 2014 Board Approved Budget DSM volumes are used as an estimate of 2014 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2014 LRAM amounts which will be filed later in 2015 will exclude the impact on Rate 1 and Rate 6 customers. This is the same approach as used in prior years (see, for example, EB-2014-0195, at Exhibit B, Tab 3, Schedule 2).

TABLE 1
2014 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Exhibit Reference:	EB-2012-0459, Exhibit C1, Tab 2, Schedule 1, Appendix A, Page 4									Unit Rate of the Revenue Impact, exclusive of gas costs	
	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
			=Col. 2-1		=Col. 3*4			=Col. 7-6	=Col. 5-8		=Col. 9*10
Rate Class	2014 Budget Annual Use (m^3)	2014 Normalized Actual Annual Use (m^3)	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2014 DSM Budget (10^6m^3)	2014 DSM Actual (10^6m^3)	DSM Volumetric Variance (10^6m^3)	Normalized Volumetric Variance Excluding DSM (10^6m^3)	Unit Rate ($/$m^3$)	AUTUVA: Revenue Impact, Exclusive of Gas Costs - ($ millions)
1	2,433	2,475	41	1,899,633	78.7	(0.7)	(0.7)	0.0	78.7	0.0463	3.65
6	28,383	28,634	251	159,575	40.1	(19.5)	(19.5)	0.0	40.1	0.0312	1.25
Total					118.8	(20.1)	(20.1)	0.0	118.8		4.90

Witness: M. Suarez

2014 POST-RETIREMENT TRUE-UP VARIANCE ACCOUNT (PTUVA)

1. As approved within the EB-2012-0459 Rate Order, Appendix A, page 24, the purpose of PTUVA is to record the differences between the 2014 forecast pension and post-employment benefit expenses of $37.2 million and the actual pension and post-employment benefit expenses (both determined on an accrual basis).

2. As of December 31, 2014 the actual pension and post-employment benefit ("OPEB") expense was $31.0 million, as calculated by Mercer. A breakdown of the $31.0 million is as follows:

	$ million
Registered Pension Plan	22.5
Supplementary Executive Retirement Plan	0.5
Supplementary Pension Plan	1.3
Defined contribution	1.0
Total pension expense	25.3
OPEB expense	5.7
Total pension and OPEB expense	31.0

3. Please refer to the attached Appendix 1 for an extract of the 2014 Final Accounting Mercer Reports that supports the figures above.

4. Therefore, the 2014 PTUVA balance is $6.2 million, which is the difference between the Board-approved forecast of $37.2 million and the actual expense of $31.0 million. The Company is requesting to refund and clear this balance within this proceeding and in accordance with the EB-2012-0459 approved variance account scope, the maximum amount that will be refunded to ratepayers will be $5 million, and the remaining amount will be transferred to the 2015 PTUVA for future clearance.

Witnesses: J. Barradas
J. Shem

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2014
Final US GAAP - January 16, 2015
Enbridge Gas Distribution Pension Plans - RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
A. Change in benefit obligation				
Benefit obligation at beginning of year	825,707,600	15,020,900	8,621,500	849,350,000
Service cost	22,305,800	573,500	621,400	23,500,700
Interest cost	40,353,300	734,500	421,800	41,509,600
Employee contributions	-	-	-	-
Special termination benefits	-	-	-	-
Benefits paid from the plan	(38,031,300)	(635,200)	(266,000)	(38,932,500)
Net transfer in/(out)	-	-	-	-
Actuarial loss (gain)	136,549,400	3,335,200	2,316,400	142,201,000
Benefit obligation at end of year	986,884,800	19,028,900	11,715,100	1,017,628,800
B. Change in plan assets				
Fair value of plan assets at beginning of year	815,296,600	13,208,500	6,341,100	834,846,200
Actual return on plan assets	91,034,400	1,499,900	733,400	93,267,700
Employer contributions	38,039,800	982,000	2,041,000	41,062,800
Employee contributions	-	-	-	-
Benefits paid	(38,031,300)	(635,200)	(266,000)	(38,932,500)
DC contributions paid from DB surplus	-	-	-	-
Net transfer in (out)	-	-	-	-
Fair value of plan assets at end of year	906,339,500	15,055,200	8,849,500	930,244,200
C. Reconciliation of funded status				
Fair value of plan assets	906,339,500	15,055,200	8,849,500	930,244,200
Benefit obligations	986,884,800	19,028,900	11,715,100	1,017,628,800
Net asset (obligation) recognized in statement of financial position	(80,545,300)	(3,973,700)	(2,865,600)	(87,384,600)
D. Amounts recognized on the consolidated balance sheet position consists of				
Noncurrent assets	-	-	-	-
Current liabilities	-	-	-	-
Noncurrent liabilities	(80,545,300)	(3,973,700)	(2,865,600)	(87,384,600)
Net asset (obligation) recognized in statement of financial position	(80,545,300)	(3,973,700)	(2,865,600)	(87,384,600)
E. Reconciliation of amounts recognized in statement of financial position				
Initial net asset(obligation)	-	-	-	-
Prior service credit (cost)	-	-	-	-
Net gain (loss)	(331,937,200)	(8,084,200)	(3,115,900)	(341,137,300)
Accumulated other comprehensive income (loss)	(331,937,200)	(6,084,200)	(3,115,900)	(341,137,300)
Accumulated contributions in excess of net periodic benefit cost	251,391,900	2,110,500	250,300	253,752,700
Net asset (obligation) recognized in statement of financial position	(80,545,300)	(3,973,700)	(2,865,600)	(87,384,600)
F. Components of net periodic benefit cost				
Service cost	22,305,800	573,500	621,400	23,500,700
Interest cost	40,353,300	734,500	421,800	41,509,600
Expected return on plan assets	(55,542,000)	(907,000)	(456,600)	(56,905,600)
Amortization of initial net obligation (asset)	-	-	-	-
Amortization of prior service cost	-	-	-	-
Amortization of net (gain) loss	15,416,800	191,300	22,300	15,630,400
Net periodic benefit cost	22,533,900	592,300	608,900	23,735,100
Headcounts for expense[1]				
EGD RPP - DB service cost provision	1,870	70	77	2,017

[1] Note the 2014 expense is based on headcount as at December 31, 2012

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2014

Final US GAAP - January 16, 2015

Enbridge Inc. Pension Plans - RPP

	Enbridge Inc.	Enbridge Pipelines Inc.	Enbridge Pipelines (Athabasca) Inc.	Enbridge Technology Inc.	Enbridge International Inc.	Enbridge Saskatchewan Operating Services Inc.	Enbridge Operational Services Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas New Brunswick Inc.	Tidal Energy Marketing Inc.	Total
A. Change in benefit obligation											
Benefit obligation at beginning of year	79,352,000	456,924,700	9,897,800	4,972,800	4,034,500	14,046,100	3,115,300	5,403,400	105,700	2,624,500	580,476,800
Service cost	10,982,800	39,402,000	1,241,700	203,800	289,000	1,872,800	293,900	-	-	758,100	55,044,100
Interest cost	3,921,700	22,581,900	489,200	245,800	199,400	694,200	154,000	267,000	5,200	129,700	28,688,100
Employee contributions	-	-	-	-	-	-	-	-	-	-	-
Plan amendments	-	-	-	-	-	-	-	-	-	-	-
Benefits paid	(2,674,600)	(14,984,800)	(157,200)	(27,300)	(16,900)	(215,600)	(42,500)	(152,600)	-	(57,200)	(18,308,700)
Net transfer in (out)	1,547,800	(4,243,900)	37,400	1,676,200	827,500	195,100	-	(40,100)	-	-	-
Actuarial loss (gain)	23,746,500	115,005,500	4,247,000	1,256,600	1,077,300	4,729,000	1,328,200	932,500	15,600	1,191,800	153,530,000
Benefit obligation at end of year	116,876,200	614,705,400	15,755,900	8,327,900	6,410,800	21,321,600	4,848,900	6,410,200	126,500	4,646,900	799,430,300
B. Change in plan assets											
Fair value of plan assets at beginning of year	75,524,900	422,826,000	8,604,600	4,457,100	4,310,000	12,236,200	2,196,000	6,028,800	110,100	2,523,900	538,817,600
Actual return on plan assets	7,478,000	39,711,300	855,200	481,000	448,300	1,201,900	222,300	544,200	10,200	268,900	51,221,300
Employer contributions	14,697,200	52,616,900	1,685,600	324,600	665,500	2,053,800	481,800	281,700	6,300	868,600	73,682,000
Employee contributions	-	-	-	-	-	-	-	-	-	-	-
Benefits paid	(2,674,600)	(14,984,800)	(157,200)	(27,300)	(16,900)	(215,600)	(42,500)	(152,600)	-	(57,200)	(18,308,700)
DC contributions paid from DB surplus	-	-	-	-	-	-	-	-	-	-	-
Net transfer in (out)	1,361,100	(3,873,700)	44,200	1,562,800	768,700	172,000	-	(35,100)	-	-	-
Fair value of plan assets at end of year	96,386,600	496,315,700	11,032,400	6,798,200	6,175,600	15,448,300	2,857,600	6,667,000	126,600	3,604,200	645,412,200
C. Reconciliation of funded status											
Market value of plan assets	96,386,600	496,315,700	11,032,400	6,798,200	6,175,600	15,448,300	2,857,600	6,667,000	126,600	3,604,200	645,412,200
Benefit obligations	116,876,200	614,705,400	15,755,900	8,327,900	6,410,800	21,321,600	4,848,900	6,410,200	126,500	4,646,900	799,430,300
Net asset (obligation) recognized in statement of financial position	(20,489,600)	(118,389,700)	(4,723,500)	(1,529,700)	(235,200)	(5,873,300)	(1,991,300)	256,800	100	(1,042,700)	(154,018,100)
D. Amounts recognized on the consolidated balance sheet position consists of											
Noncurrent assets	-	-	-	-	-	-	-	256,800	100	-	
Current liabilities	-	-	-	-	-	-	-	-	-	-	
Noncurrent liabilities	(20,489,600)	(118,389,700)	(4,723,500)	(1,529,700)	(235,200)	(5,873,300)	(1,991,300)	-	-	(1,042,700)	
Net asset (obligation) recognized in statement of financial position	(20,489,600)	(118,389,700)	(4,723,500)	(1,529,700)	(235,200)	(5,873,300)	(1,991,300)	256,800	100	(1,042,700)	
The aggregate of results on an individual basis will not match the total plan											
E. Reconciliation of amounts recognized in statements of financial position											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(6,300)	(191,400)	-	(1,300)	(2,500)	(1,300)	-	(1,300)	-	-	(204,100)
Net gain (loss)	(39,519,600)	(221,000,400)	(6,082,000)	(1,700,100)	(1,794,000)	(7,274,200)	(2,002,100)	(2,478,200)	(71,700)	(1,313,900)	(283,236,200)
Accumulated other comprehensive income (loss)	(39,525,900)	(221,191,800)	(6,082,000)	(1,701,400)	(1,796,500)	(7,275,500)	(2,002,100)	(2,479,500)	(71,700)	(1,313,900)	(283,440,300)
Accumulated contributions in excess of net periodic benefit cost	19,036,300	102,802,100	1,358,500	171,700	1,561,300	1,402,200	10,800	2,736,300	71,800	271,200	129,422,200
Net asset (obligation) recognized in statement of financial position	(20,489,600)	(118,389,700)	(4,723,500)	(1,529,700)	(235,200)	(5,873,300)	(1,991,300)	256,800	100	(1,042,700)	(154,018,100)
F. Components of net periodic benefit cost											
Service cost	10,982,800	39,402,000	1,241,700	203,800	289,000	1,872,800	293,900	-	-	758,100	55,044,100
Interest cost	3,921,700	22,581,900	489,200	245,800	199,400	694,200	154,000	267,000	5,200	129,700	28,688,100
Expected return on plan assets	(5,652,000)	(30,926,900)	(639,400)	(321,100)	(315,300)	(919,000)	(166,400)	(430,900)	(7,900)	(199,000)	(39,577,900)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	5,000	153,100	-	1,000	2,000	1,000	-	1,000	-	-	163,100
Amortization of net (gain) loss	853,000	6,097,700	93,700	9,400	37,000	125,600	36,900	93,200	4,200	(6,200)	7,344,500
Net periodic benefit cost	10,110,500	37,307,800	1,185,200	138,900	212,100	1,774,600	318,400	(69,700)	1,500	682,600	51,661,900
Headcounts for expense[1]											
EI RPP - DB service cost provision	432	1,863	72	7	10	111	17	-	-	27	2,539
[1] Note the 2014 expense is based on headcount as at December 31, 2012											
G. Changes recognized in other comprehensive income											
Changes in plan assets and benefit obligations recognized in other comprehensive income											
New prior service cost	-	-	-	-	-	-	-	-	-	-	-
Net loss (gain) arising during the year	21,920,500	106,221,100	4,031,200	1,096,700	944,300	4,446,100	1,272,300	819,200	13,300	1,121,900	141,886,600
Amounts recognized as a component of net periodic benefit cost											
Amortization or curtailment recognition of prior service credit (cost)	(5,000)	(153,100)	-	(1,000)	(2,000)	(1,000)	-	(1,000)	-	-	(163,100)
Amortization or settlement recognition of net gain (loss)	(853,000)	(6,097,700)	(93,700)	(9,400)	(37,000)	(125,600)	(36,900)	(93,200)	(4,200)	6,200	(7,344,500)
Total recognized in other comprehensive loss (income)	21,062,500	99,970,300	3,937,500	1,086,300	905,300	4,319,500	1,235,400	725,000	9,100	1,128,100	134,379,000
Total recognized in net periodic benefit and other comprehensive loss (income)	31,173,000	137,278,100	5,122,700	1,225,200	1,117,400	6,094,100	1,553,800	655,300	10,600	1,810,700	186,040,900
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(5,000)	(153,100)	-	(1,000)	(2,000)	(1,000)	-	(1,000)	-	-	(163,100)
Net gain (loss)	(2,150,500)	(12,026,100)	(331,000)	(92,500)	(97,600)	(395,800)	(108,900)	(134,900)	(3,900)	(71,500)	(15,412,700)

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Final Accounting Disclosure for Enbridge Canadian Pension Plans

Plan Name:	Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates		Supplemental Executive Retirement Plan of Enbridge Gas Distribution and Affiliates		Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc.	
Country	Canada	Canada	Canada	Canada	Canada	Canada
Fiscal year ending on	12/31/2014	12/31/2013	12/31/2014	12/31/2013	12/31/2014	12/31/2013
D. Amounts recognized on the consolidated balance sheet position consists of						
1. Noncurrent assets	-	-	1,207,700	2,006,800	3,860,200	3,377,100
2. Current liabilities	-	-	-	-	-	-
3. Noncurrent liabilities	(87,384,600)	(14,503,800)	-	-	-	-
4. Net amount [asset (obligation)] recognized in statement of financial position	(87,384,600)	(14,503,800)	1,207,700	2,006,800	3,860,200	3,377,100
E. Reconciliation of amounts recognized in statement of financial position						
1. Initial net asset(obligation)	-	-	-	-	-	-
2. Prior service credit (cost)	-	-	-	-	-	-
3. Net gain (loss)	(341,137,300)	(250,928,800)	(3,883,300)	(3,336,700)	244,600	(209,300)
4. Accumulated other comprehensive income (loss)	(341,137,300)	(250,928,800)	(3,883,300)	(3,336,700)	244,600	(209,300)
5. Accumulated contributions in excess of net periodic benefit cost	253,752,700	236,425,000	5,091,000	5,343,500	3,615,600	3,586,400
6. Net amount [surplus (deficit)] recognized in statement of financial position	(87,384,600)	(14,503,800)	1,207,700	2,006,800	3,860,200	3,377,100
F. Components of net periodic benefit cost						
1. Service cost	23,500,700	24,926,900	-	-	-	-
2. Interest cost	41,509,600	37,167,400	721,800	649,200	219,000	196,600
3. Expected return on plan assets	(56,905,600)	(51,268,700)	(530,900)	(497,500)	(248,200)	(239,900)
4. Amortization of initial net obligation (asset)	-	-	-	-	-	-
5. Amortization of prior service cost	-	1,212,900	-	-	-	-
6. Amortization of net (gain) loss	15,630,400	26,868,300	369,000	778,500	-	-
7. Curtailment (gain) / loss recognized	-	-	-	-	-	-
8. Settlement (gain) / loss recognized	-	-	-	-	-	-
9. Special termination benefit recognized	-	-	-	-	-	-
10. Net periodic benefit cost	23,735,100	38,906,800	559,900	930,200	(29,200)	(43,300)
G. Changes recognized in other comprehensive income						
Changes in plan assets and benefit obligations recognized in other comprehensive income						
1. New prior service cost	-	-	-	-	-	-
2. Net loss (gain) arising during the year*	105,838,900	(88,394,200)	915,600	(1,284,800)	(453,900)	(408,800)
3. Effect of exchange rates on amounts included in AOCI	-	-	-	-	-	-
Amounts recognized as a component of net periodic benefit cost						
4. Amortization, settlement or curtailment recognition of net transition asset (obligation)	-	-	-	-	-	-
5. Amortization or curtailment recognition of prior service credit (cost)	-	(1,212,900)	-	-	-	-
6. Amortization or settlement recognition of net gain (loss)	(15,630,400)	(26,868,300)	(369,000)	(778,500)	-	-
7. Total recognized in other comprehensive loss (income)	90,208,500	(114,475,400)	546,600	(2,063,300)	(453,900)	(408,800)
8. Total recognized in net periodic benefit and other comprehensive loss (income)	113,943,600	(75,568,600)	1,106,500	(1,133,100)	(483,100)	(452,100)

**Includes curtailment gains not recognized as a component of net periodic cost*

Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year	12/31/2014	12/31/2014	12/31/2014
9. Initial net asset (obligation)	-	-	-
10. Prior service credit (cost)	-	-	-
11. Net gain (loss)	(18,556,100)	(423,400)	-
	(18,556,100)	(423,400)	-

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2014

Final US GAAP - January 16, 2015
Enbridge Inc. Pension Plans - SPP

	Enbridge Inc.	Enbridge Pipelines Inc.	Enbridge Pipelines (Athabasca) Inc.	Enbridge Technology Inc.	Enbridge International Inc.	Enbridge Saskatchewan Operating Services Inc.	Enbridge Operational Services Inc.	Enbridge Gas Distribution Inc.	Enbridge Gas New Brunswick Inc.	Tidal Energy Marketing Inc.	Total
A. Change in benefit obligation											
Benefit obligation at beginning of year	94,519,000	53,782,600	112,500	546,500	3,105,500	692,500	-	12,962,100	-	584,400	166,305,100
Service cost	4,258,100	3,839,500	26,100	-	199,300	45,000	-	1,229,600	-	315,600	9,913,200
Interest cost	4,645,500	2,643,300	5,600	27,300	155,300	34,600	-	637,100	-	28,700	8,177,400
Employee contributions	-	-	-	-	-	-	-	-	-	-	-
Plan amendments	-	-	-	-	-	-	-	-	-	-	-
Benefits paid	(3,539,700)	(1,000,200)	-	-	-	-	-	(207,800)	-	-	(4,747,700)
Net transfer in (out)	2,828,000	(1,858,600)	-	-	893,200	4,200	-	(1,866,800)	-	-	-
Actuarial loss (gain)	18,001,700	16,996,300	159,800	162,800	1,150,500	246,700	30,800	2,767,000	-	403,600	39,919,200
Benefit obligation at end of year	120,712,600	74,402,900	304,000	736,600	5,503,800	1,023,000	30,800	15,521,200	-	1,332,300	219,567,200
B. Change in plan assets											
Fair value of plan assets at beginning of year	105,347,100	39,850,200	95,300	665,500	5,907,600	157,800	138,700	14,254,800	256,900	592,300	167,266,200
Actual return on plan assets	8,760,400	3,239,000	9,600	76,100	753,600	16,300	15,900	1,193,100	29,400	55,800	14,149,200
Employer contributions	4,231,200	3,313,900	24,300	1,100	239,300	39,500	-	1,038,000	-	215,800	9,103,100
Employee contributions	-	-	-	-	-	-	-	-	-	-	-
Benefits paid	(3,539,700)	(1,000,200)	-	-	-	-	-	(207,800)	-	-	(4,747,700)
DC contributions paid from DB surplus	-	-	-	-	-	-	-	-	-	-	-
Net transfer in (out)	2,761,100	(1,870,300)	-	-	867,000	3,900	-	(1,761,700)	-	-	-
Fair value of plan assets at end of year	117,560,100	43,532,600	129,200	742,700	7,767,500	217,500	154,600	14,516,400	286,300	863,900	185,770,800
C. Reconciliation of funded status											
Fair value of plan assets	117,560,100	43,532,600	129,200	742,700	7,767,500	217,500	154,600	14,516,400	286,300	863,900	185,770,800
Benefit obligations	120,712,600	74,402,900	304,000	736,600	5,503,800	1,023,000	30,800	15,521,200	-	1,332,300	219,567,200
Net asset (obligation) recognized in statement of financial position	(3,152,500)	(30,870,300)	(174,800)	6,100	2,263,700	(805,500)	123,800	(1,004,800)	286,300	(468,400)	(33,796,400)
D. Amounts recognized on the consolidated balance sheet position consists of											
Noncurrent assets	-	-	-	6,100	2,263,700	-	123,800	-	286,300	-	
Current liabilities	-	-	-	-	-	-	-	-	-	-	
Noncurrent liabilities	(3,152,500)	(30,870,300)	(174,800)	-	-	(805,500)	-	(1,004,800)	-	(468,400)	
Net asset (obligation) recognized in statement of financial position	(3,152,500)	(30,870,300)	(174,800)	6,100	2,263,700	(805,500)	123,800	(1,004,800)	286,300	(468,400)	
The aggregate of results on an individual basis will not match the total plan											
E. Reconciliation of amounts recognized in statement of financial position											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(19,900)	-	-	-	-	-	-	-	-	-	(19,900)
Net gain (loss)	(46,285,900)	(33,044,200)	(232,600)	(283,400)	(1,562,300)	(516,500)	(41,000)	(6,858,500)	(135,400)	(788,500)	(89,748,300)
Accumulated other comprehensive income (loss)	(46,305,800)	(33,044,200)	(232,600)	(283,400)	(1,562,300)	(516,500)	(41,000)	(6,858,500)	(135,400)	(788,500)	(89,768,200)
Accumulated contributions in excess of net periodic benefit cost	43,153,300	2,173,900	57,800	289,500	3,826,000	(289,000)	164,800	5,853,700	421,700	320,100	55,971,800
Net asset (obligation) recognized in statement of financial position	(3,152,500)	(30,870,300)	(174,800)	6,100	2,263,700	(805,500)	123,800	(1,004,800)	286,300	(468,400)	(33,796,400)
F. Components of net periodic benefit cost											
Service cost	4,258,100	3,839,500	26,100	-	199,300	45,000	-	1,229,600	-	315,600	9,913,200
Interest cost	4,645,500	2,643,300	5,600	27,300	155,300	34,600	-	637,100	-	28,700	8,177,400
Expected return on plan assets	(5,846,600)	(2,191,800)	(5,700)	(37,300)	(323,700)	(9,600)	(7,500)	(807,200)	(13,900)	(38,700)	(9,282,000)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	1,800	-	-	-	-	-	-	-	-	-	1,800
Amortization of net (gain) loss	1,908,200	1,045,600	4,700	9,800	51,500	16,900	1,100	273,800	9,200	24,600	3,345,400
Net periodic benefit cost	4,967,000	5,336,600	30,700	(200)	82,400	86,900	(6,400)	1,333,300	(4,700)	330,200	12,155,800
Headcounts for expense1											
EI SPP (Only Senior Management Employees)	70	78	1	-	4	1	-	33	-	7	194
1 Note the 2014 expense is based on headcount as at December 31, 2012											
G. Changes recognized in other comprehensive income											
Changes in plan assets and benefit obligations recognized in other comprehensive income											
New prior service cost	-	-	-	-	-	-	-	-	-	-	-
Net loss (gain) arising during the year	15,087,900	15,949,100	155,900	124,000	720,600	240,000	22,400	2,381,100	(15,500)	386,500	35,052,000
Amounts recognized as a component of net periodic benefit cost											
Amortization or curtailment recognition of prior service credit (cost)	(1,800)	-	-	-	-	-	-	-	-	-	(1,800)
Amortization or settlement recognition of net gain (loss)	(1,908,200)	(1,045,600)	(4,700)	(9,800)	(51,500)	(16,900)	(1,100)	(273,800)	(9,200)	(24,600)	(3,345,400)
Total recognized in other comprehensive loss (income)	13,177,900	14,903,500	151,200	114,200	669,100	223,100	21,300	2,107,300	(24,700)	361,900	31,704,800
Total recognized in net periodic benefit and other comprehensive loss (income)	18,144,900	20,240,100	181,900	114,000	751,500	310,000	14,900	3,440,600	(29,400)	692,100	43,860,600
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(1,800)	-	-	-	-	-	-	-	-	-	(1,800)
Net gain (loss)	(2,658,600)	(1,898,100)	(13,400)	(16,300)	(89,700)	(29,700)	(2,400)	(394,000)	(7,800)	(45,300)	(5,155,300)

MERCER

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2014
Final US GAAP - January 16, 2015
Enbridge Gas Distribution Pension Plans - RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Q. DC Current service cost	962,500	53,700	45,900	1,062,100
Projected DC current service cost for fiscal year ending:				
31-Dec-2015 :	987,900	74,800	57,900	1,120,600
31-Dec-2016 :	1,022,500	77,400	59,900	1,159,800
31-Dec-2017 :	1,058,300	80,100	62,000	1,200,400
31-Dec-2018 :	1,095,300	82,900	64,200	1,242,400
31-Dec-2019 :	1,133,600	85,800	66,400	1,285,800
31-Dec-2020 :	1,173,300	88,800	68,700	1,330,800
31-Dec-2021 :	1,214,400	91,900	71,100	1,377,400
31-Dec-2022 :	1,256,900	95,100	73,600	1,425,600
31-Dec-2023 :	1,300,900	98,400	76,200	1,475,500
31-Dec-2024 :	1,346,400	101,800	78,900	1,527,100

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2014
US GAAP - January 16, 2015
Enbridge Gas Distribution Non-Pension Post Retirement Benefit Plan

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Reconciliation of amounts recognized in statement of financial position				
Initial net asset(obligation)	-	-	-	-
Prior service credit (cost)	(1,849,000)	(31,000)	(14,000)	(1,894,000)
Net gain (loss)	(7,445,200)	(725,000)	(69,000)	(8,239,200)
Accumulated other comprehensive income (loss)	(9,294,200)	(756,000)	(83,000)	(10,133,200)
Accumulated contributions in excess of net periodic benefit cost	(94,785,800)	(1,198,000)	(1,166,000)	(97,149,800)
Net amount [surplus (deficit)] recognized in statement of financial position	(104,080,000)	(1,954,000)	(1,249,000)	(107,283,000)
Components of net periodic benefit cost				
Service cost	1,127,000	48,000	53,000	1,228,000
Interest cost	4,520,000	78,000	49,000	4,647,000
Expected return on plan assets	-	-	-	-
Amortization of initial net obligation (asset)	-	-	-	-
Amortization of prior service cost	103,000	2,000	1,000	106,000
Amortization of net (gain) loss	-	-	-	-
Net periodic benefit cost	5,750,000	128,000	103,000	5,981,000
Changes recognized in other comprehensive income				
Changes in plan assets and benefit obligations recognized in other comprehensive income				
New prior service cost	-	-	-	-
Net loss (gain) arising during the year	9,407,000	296,000	185,000	9,888,000
Amounts recognized as a component of net periodic benefit cost				
Amortization or curtailment recognition of prior service credit (cost)	(103,000)	(2,000)	(1,000)	(106,000)
Amortization or settlement recognition of net gain (loss)	-	-	-	-
Total recognized in other comprehensive loss (income)	9,304,000	294,000	184,000	9,782,000
Total recognized in net periodic benefit and other comprehensive loss (income)	15,054,000	422,000	287,000	15,763,000
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year				
Initial net asset (obligation)	-	-	-	-
Prior service credit (cost)	(103,000)	(2,000)	(1,000)	(106,000)
Net gain (loss)	-	-	-	-

GAS DISTRIBUTION ACCESS RULE IMPACT DEFERRAL ACCOUNT

1. Within the EB-2012-0459 Final Accounting Order, the Board approved the 2014 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA") to record impacts associated with the Company maintaining compliance with the Board's Gas Distribution Access Rule ("GDAR") directives.

2. While there were no amendments to GDAR directives during 2014, the Company has included for recovery within the 2014 GDARIDA, the 2014 revenue requirement impact resulting from the Low Income Customer Service Rule ("LICSR") changes which came into effect on January 1, 2013 through an amendment to GDAR which the Board adopted on September 6, 2012.

3. As was indicated within the Clearance of 2013 Deferral and Variance Accounts and 2012 DSM Related Accounts proceeding, EB-2014-0195, at Exhibit B, Tab 3, Schedule 3, Enbridge was not able to include a forecast of the impacts of the change in the GDAR low income customer service rule at the time of forecasting its 2013 revenue requirement within its 2013 Test Year rate proceeding, EB-2011-0354, which also served as the base for the 2014 through 2018 Custom Incentive Regulation plan approved in EB-2012-0459.

4. Within the EB-2014-0195 proceeding, the Company requested and received Board approval to credit to ratepayers the 2013 revenue requirement resulting from the capital spending incurred to implement the Low Income Customer Service Rule ("LICSR") changes. Within that proceeding, the Company also indicated that there would be 2014 through 2018 revenue requirement impacts resulting from the LICSR capital spending to be recovered through the GDAR deferral account.

5. As mentioned above, within this proceeding the Company has included for recovery within the 2014 GDARIDA, the 2014 revenue requirement, determined through a cost of service type calculation, which results from the LICSR changes. The Company is proposing to recover from ratepayers $0.153 million as part of the requested one time rate rider adjustment in October 2015, as shown in the proposed clearance balances at Exhibit C, Tab 1, Schedule 1, page 3, Columns 3 and 4.

6. The determination of the 2014 revenue requirement amount is shown on pages 3 through 7 of this schedule. Included within the revenue requirement calculation requested for recovery are the typical items included within a cost of service revenue requirement, such as depreciation, taxes, and total return on rate base (including interest and return on equity). The Company has used the 2014 actual required capital structure within the 2014 revenue requirement calculation. The approved 2013 revenue requirement, credited to ratepayers as part of the EB-2014-0195 proceeding, is also shown for continuity.

UTILITY CAPITAL STRUCTURE
2014 GDARIDA IMPACTS

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2013 Actual Capital Structure			2014 Actual Capital Structure		
		Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component
		%	%	%	%	%	%
1.	Long-term debt	56.16	5.84	3.28	57.55	5.41	3.11
2.	Short-term debt	5.51	1.11	0.06	4.32	1.38	0.06
3.		61.67		3.34	61.87		3.17
4.	Preference shares	2.33	2.40	0.06	2.13	2.40	0.05
5.	Common equity	36.00	8.93	3.21	36.00	9.36	3.37
6.	Required Return on Rate Base	100.00		6.61	100.00		6.59

	($000's)	2013	2014
7.	Ontario Utility Income	70.9	(63.7)
8.	Rate base	238.4	736.0
9.	Indicated rate of return	29.74 %	(8.65)%
10.	(Def.) / suff. in rate of return	23.13 %	(15.24)%
11.	Net (def.) / suff.	55.1	(112.2)
12.	Gross (def.) / suff.	75.0	(152.7)

Witnesses: D. McIlwraith
R. Small

UTILITY RATE BASE
2014 GDARIDA IMPACTS

($000's)

Line No.		2013	2014
	Property, plant, and equipment		
1.	Cost or redetermined value	260.1	876.3
2.	Accumulated depreciation	(21.7)	(140.3)
3.		238.4	736.0
	Allowance for working capital		
4.	Accounts receivable rebillable projects	-	-
5.	Materials and supplies	-	-
6.	Mortgages receivable	-	-
7.	Customer security deposits	-	-
8.	Prepaid expenses	-	-
9.	Gas in storage	-	-
10.	Working cash allowance	-	-
11.		-	-
12.	Ontario utility rate base	238.4	736.0

Witnesses: D. McIlwraith
R. Small

UTILITY INCOME
2014 GDARIDA IMPACTS

($000's)

Line No.		2013	2014
	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	47.3	186.0
10.	Municipal and other taxes	-	-
11.	Total costs and expenses	47.3	186.0
12.	Utility income before inc. taxes	(47.3)	(186.0)
	Income taxes		
13.	Excluding interest shield	(116.1)	(116.1)
14.	Tax shield on interest expense	(2.1)	(6.2)
15.	Total income taxes	(118.2)	(122.3)
16.	Ontario utility net income	70.9	(63.7)

Witnesses: D. McIlwraith
R. Small

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2014 GDARIDA IMPACTS

($000's)

Line No.		2013	2014
1.	Utility income before income taxes	(47.3)	(186.0)
	Add Backs		
2.	Depreciation and amortization	47.3	186.0
3.	Large corporation tax	-	-
4.	Other non-deductible items	-	-
5.	Any other add back(s)	-	-
6.	Total added back	47.3	186.0
7.	Sub total - pre-tax income plus add backs	-	-
	Deductions		
8.	Capital cost allowance - Federal	438.2	438.1
9.	Capital cost allowance - Provincial	438.2	438.1
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	438.2	438.1
17.	Total Deductions - Provincial	438.2	438.1
18.	Taxable income - Federal	(438.2)	(438.1)
19.	Taxable income - Provincial	(438.2)	(438.1)
20.	Income tax provision - Federal	(65.7)	(65.7)
21.	Income tax provision - Provincial	(50.4)	(50.4)
22.	Income tax provision - combined	(116.1)	(116.1)
23.	Part V1.1 tax	-	-
24.	Investment tax credit	-	-
25.	Total taxes excluding tax shield on interest expense	(116.1)	(116.1)
	Tax shield on interest expense		
26.	Rate base as adjusted	238.4	736.0
27.	Return component of debt	3.34%	3.17%
28.	Interest expense	8.0	23.3
29.	Combined tax rate	26.500%	26.500%
30.	Income tax credit	(2.1)	(6.2)
31.	Total income taxes	(118.2)	(122.3)

Witnesses: D. McIlwraith
R. Small

UTILITY REVENUE REQUIREMENT
2014 GDARIDA IMPACTS

($000's)

Line No.		2013	2014
	Cost of capital		
1.	Rate base	238.4	736.0
2.	Required rate of return	6.61%	6.59%
3.	Cost of capital	15.8	48.5
	Cost of service		
4.	Gas costs	-	-
5.	Operation and Maintenance	-	-
6.	Depreciation and amortization	47.3	186.0
7.	Municipal and other taxes	-	-
8.	Cost of service	47.3	186.0
	Misc. & Non-Op. Rev		
9.	Other operating revenue	-	-
10.	Other income	-	-
11.	Misc, & Non-operating Rev.	-	-
	Income taxes on earnings		
12.	Excluding tax shield	(116.1)	(116.1)
13.	Tax shield provided by interest expense	(2.1)	(6.2)
14.	Income taxes on earnings	(118.2)	(122.3)
	Taxes on (def) / suff.		
15.	Gross (def.) / suff.	75.0	(152.7)
16.	Net (def.) / suff.	55.1	(112.2)
17.	Taxes on (def.) / suff.	(19.9)	40.5
18.	Revenue requirement	(75.0)	152.7
	Revenue at existing Rates		
19.	Gas sales	0.0	0.0
20.	Transportation service	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0
22.	Rounding adjustment	0.0	0.0
23.	Revenue at existing rates	0.0	0.0
24.	Gross revenue (def.) / suff.	75.0	(152.7)

Witnesses: D. McIlwraith
R. Small

2014 DEFERRED REBATE ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2015

1. The 2014 Deferred Rebate Account ("DRA") was approved by the Board within the EB-2012-0459 Final Accounting Order at Appendix A, page 18. The description and scope of the 2014 account, consistent with prior fiscal years, was to record any amounts payable to, or receivable from, customers as a result of clearing Deferral and Variance Accounts, which remain outstanding due to the inability to locate such customers.

2. The $(3.2) million recorded in the 2014 DRA and requested for clearance, reflects the outstanding amount resulting from the 2014 Rider E Deferral Account clearance, which occurred in January 2015, and the inability to locate all of the intended customers.

Witness: R. Small

2015 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2015

1. The purpose of the Transition Impact of Accounting Changes Deferral Account ("TIACDA") is to track the un-cleared Other Post Employment Benefit ("OPEB") costs which the Board has approved for recovery. Within EB-2011-0354, the Board approved the recovery of OPEB costs, which were forecast to be $90 million at the end of 2012, evenly over a 20 year period, commencing in 2013. The OPEB costs needed to be recognized as a result of Enbridge having to account for post-employment expenses on an accrual basis, upon transition to USGAAP for corporate reporting purposes in 2012. The use of USGAAP for regulatory purposes was approved within the 2013 rate proceeding, EB-2011-0354.

2. The final amount recorded in the TIACDA as of the end of 2012 was $88.716 million. The first and second, or 2013 and 2014 installments of $4.436 million each (1/20 of $88.716 million), were approved for recovery within the EB-2013-0046 and EB-2014-0195 proceedings.

3. Enbridge is now requesting recovery of the third, or 2015 installment of the Board-Approved TIACDA amount, in the amount of $4.436 million (1/20 of $88.716 million).

4. As per the approved description and scope of the account, interest is not applicable to the balances to be cleared from the TIACDA.

Witness: R. Small

2013 AND 2014 CUSTOMER CARE CIS RATE SMOOTHING DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2015

1. Within the Customer Care and CIS Costs Settlement Agreement and proceeding EB-2011-0226, the Board approved of a Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"), for each of 2013 through 2018. The purpose of the account is to capture the difference between the forecast customer care and CIS costs (as approved in EB-2011-0226) versus the amount to be collected in revenues in each year. The amount to be debited or credited to the Deferral Account in each year will be calculated by multiplying the difference in approved cost per customer and smoothed cost per customer for that year, by the updated customer forecast for that year.

2. The Settlement Agreement also specified that the balances in the account will not be cleared during the 2013 through 2018 period. The cumulative balance will build up during the years 2013 to 2015 when the approved cost per customer exceeds the smoothed cost per customer being collected in rates, and then will be drawn down during the years 2016 to 2018 when the approved cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account it is to be cleared along with the clearance of other Deferral and Variance Accounts.

3. The Settlement Agreement also specified that Enbridge would be entitled to collect interest, at a fixed annual rate of 1.47%, on the balances in the CCCISRSDAs, and that interest would be cleared annually at the same time as other Deferral and Variance Account clearings.

4. Within the EB-2011-0354 Final Rate Order, and EB-2012-0459 Final Accounting Order, the Board approved of the 2013 and 2014 CCCISRSDAs. The principal

balance recorded within each of the 2013 and 2014 accounts ($4.6 million and $2.9 million), reflects each year's approved variance between the forecast customer care and CIS costs and the amount incorporated into rates.

5. The Company did not request any disposition of the 2013 CCCISRSDA within the EB-2014-0195 proceeding.

6. In accordance with the EB-2011-0226 Settlement Agreement methodology (described above), the Company is not requesting clearance of the principal balances at this time, as the balances will be offset by amounts to be recorded within the 2016 through 2018 CCCISRSDAs, and if required any net cumulative balance will be requested for clearance after 2018.

7. Within this proceeding, the Company is requesting clearance of the interest balances on the 2013 and 2014 CCCISRSDAs, in the amounts of $150.6 thousand and $52 thousand, as shown in Exhibit C, Tab 1, Schedule 1, page 3. The clearance of the accumulated interest during the 2013 to 2018 term covered by the EB-2011-0226 Settlement Agreement is consistent with the approach approved in that case.

Witnesses: D. McIlwraith
R. Small

2015 CREDIT FINAL BILL DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2015

1. The 2015 Credit Final Bill Deferral Account ("CFBDA") was approved by the Board within the Settlement Agreement in Enbridge's 2015 Rate Adjustment proceeding, EB-2014-0276. The purpose of the 2015 CFBDA is to address a billing related issue which the Company has identified as resulting from the 2009 CIS implementation, specifically final bills with credit balances. The account will be used to track un-refunded customer final bill credit amounts, aged two years or more, while continuing efforts are made to return as much of the amounts as possible to the former account holders. Therefore, un-refunded final bill credit balances aged two years or more will be credited to the account. As the affected customers will always be entitled and able to receive refunds, any future refund amounts paid, relating to amounts already credited to the CFBDA, will be debited to the account. In addition, also as per the terms of the EB-2014-0276 Settlement Agreement, the account will also be credited by an amount of $319,000 in relation to estimated interest savings that resulted from the Company holding refund balances.

2. The terms of the EB-2014-0276 Settlement Agreement require the Company to request clearance of the 2015 CFBDA within the 2014 Earnings Sharing and Deferral Account Clearance Application. Therefore, the Company is requesting approval to clear the current balance, as at April 30, 2015, in the amount of $5.5 million (inclusive of the $319,000 in estimated interest savings), as well as forecast interest on that balance through September 30, 2015, within this application.

Witnesses: D. McIlwraith
R. Small

3. The current balance to be recorded in the 2015 CFBDA is reduced from the amount indicated during the 2015 Rate Adjustment proceeding (EB-2014-0276). This reflects that the Company has had some success in refunding amounts to customers with closed accounts. Specifically, the Company has had some recent success in new programming techniques to automate address and name matching between closed and active accounts within CIS. Having now completed this most recent effort to return outstanding credits, Enbridge expects to return only minor sums moving forward.

4. The 2015 CFBDA will, however, remain open for the remainder of 2015 to record any incremental un-refunded customer final bill credit amounts, aged two years or more, in addition to any offsetting incremental refund amounts paid relating to amounts already credited to the CFBDA, as compared to the balance being requested for clearance. The Company will seek clearance of any further balances recorded in the 2015 CFBDA within the 2015 Earnings Sharing proceeding.

Witnesses: D. McIlwraith
R. Small

CLEARANCE OF 2014 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The Company is proposing to clear 2014 Deferral and Variance Account balances to customers during the October 2015 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 2014 consumption volume for the period January 1, 2014 to December 31, 2014, and will be recovered or refunded as a one-time billing adjustment in October 2015.

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 2014 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 2014 consumption volumes for each rate class and each type of service.

4. The table on page 6 displays the bill adjustments in October 2015 for typical customers resulting from the clearance of the 2014 Deferral and Variance Account balances. These bill adjustments will be shown as a separate line item on customers' October 2015 bills.

5. Allocation of the balances within the Deferral and Variance Accounts to be cleared will be performed in the same manner as previous years, except in relation to four

accounts which the Company is proposing to clear for the first time: the Customer Care CIS Rate Smoothing Deferral Account (“CCCISRSDA”), the Credit Final Bill Deferral Account (“CFBDA”), the Design Day Criteria Transportation Deferral Account (“DDCTDA”), and the Unabsorbed Demand Cost Deferral Account (“UDCDA”).

CCCISRSDA:

6. The CCCISRSDA captures the difference between the forecast customer care and CIS costs versus the amount to be collected in revenues. This approach was approved by the Board in EB-2011-0226 (the Customer Care Settlement Agreement and proceeding). As stated in Exhibit C, Tab 1, Schedule 10, the Settlement Agreement also specified that the balances in the account will not be cleared during the 2013 through 2018 period. Within this proceeding, the Company is requesting clearance of the interest balances on the 2013 and 2014 CCCISRSDAs, in the amounts of $150.6 thousand and $52 thousand, as shown in Exhibit C, Tab 1, Schedule 1, page 3.

7. The Company proposes to allocate the balance of the CCCISRSDA on the basis of total number of customers by rate class. This follows how customer care and CIS costs are recovered through rates. This approach can be referenced at Exhibit C, Tab 2, Schedule 2, page 3 of 6, Line 13 and Line 14.

CFBDA:

8. The Company proposes to allocate the amounts recorded in the CFBDA directly to the rate classes from which the credit balance originate (referred to as “Direct Allocation” in the Company’s Clearance of Deferral and Variance Account

proceedings). This approach was also discussed in the response to Board Staff Interrogatory #18, filed in EB-2014-0276 (the 2015 Rate Application). This approach can be referenced at Exhibit C, Tab 2, Schedule 2, page 3 of 6, Line 8.

DDCTDA & UDCDA:

9. As part of its 2014 gas supply plan, the Company contracted for incremental long haul Firm Transportation ("FT") capacity on TCPL to meet its Peak Day requirements. To the extent the Company was unable to utilize 100% of its contracted long haul TCPL FT capacity in 2014, the associated UDC costs were debited to the UDCDA or DDCTDA. Conversely, any revenues received from the release of the unutilized capacity were credited to the UDCDA or DDCTDA.

10. In other words, the cost of additional FT capacity was incurred to provide load balancing service in peak or near-peak conditions to all bundled customers (i.e., system gas and direct purchase customers). The Company utilizes a certain amount of long haul FT in lieu of an equivalent amount of peaking service (less reliable than FT) or STFT (more expensive than FT) to meet demand in peak and near-peak conditions. Accordingly, most of these costs are recovered in rates from heat-sensitive general service customers. The UDC costs that comprise the balance of the UDCDA and DDCTDA represent the unutilized portion of the long haul FT capacity that the Company acquired for load balancing purposes. To represent cost causality, the Company proposes to clear the balance of both accounts to all bundled customers (system gas and direct purchase customers) based on the deliverability allocator under the Board approved cost allocation and rate design methodology. The deliverability allocator represents rate class demand in excess of the class' average winter demand (i.e., load balancing requirements of

each rate class in peak or near-peak conditions), and can be referenced at EB-2012-0459, Exhibit G2, Tab 6, Schedule 3, page 1, Item 3.1.

UNIT RATE AND TYPE OF SERVICE: CLEARING IN OCTOBER 2015

		COL.1 TOTAL (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	0.0134
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0242
	- WESTERN T-SERVICE	0.0134
RATE 6	- SYSTEM SALES	0.1388
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1496
	- WESTERN T-SERVICE	0.1388
RATE 9	- SYSTEM SALES	(0.9517)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.9409)
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	0.1907
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- WESTERN T-SERVICE	0.1907
RATE 110	- SYSTEM SALES	0.0649
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0757
	- WESTERN T-SERVICE	0.0649
RATE 115	- SYSTEM SALES	0.0655
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0763
	- WESTERN T-SERVICE	0.0655
RATE 135	- SYSTEM SALES	0.0488
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0596
	- WESTERN T-SERVICE	0.0488
RATE 145	- SYSTEM SALES	0.0310
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0418
	- WESTERN T-SERVICE	0.0310
RATE 170	- SYSTEM SALES	0.0489
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0597
	- WESTERN T-SERVICE	0.0489
RATE 200	- SYSTEM SALES	0.1616
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1724
	- WESTERN T-SERVICE	0.0000
Unbundled Services:		
RATE 125	- All	(1.0999)
	- Customer-specific ($)	$0
RATE 300	- All	(29.1595)

Witnesses: J. Collier
A. Kacicnik
M. Kirk

Determination of Balances to be Cleared
from the 2014 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	(1,256.7)	(11.6)	(1,268.3)
2.	UNACCOUNTED FOR GAS V/A	11,917.1	108.5	12,025.6
3.	STORAGE AND TRANSPORTATION D/A	(1,147.6)	(16.4)	(1,164.0)
4.	DEFERRED REBATE ACCOUNT	(3,167.6)	(25.2)	(3,192.8)
5.	DEMAND SIDE MANAGEMENT 2013			0.0
6.	LOST REVENUE ADJ MECHANISM 2013			0.0
7.	DEMAND SIDE MANAGEMENT INCENTIVE 2013			0.0
8.	CREDIT FINAL BILL D/A	(5,517.6)	(20.4)	(5,538.0)
9.	ONTARIO HEARING COSTS V/A	0.0	0.0	0.0
10.	GAS DISTRIBUTION ACCESS RULE D/A 2014	152.7	0.0	152.7
11.	AVERAGE USE TRUE-UP V/A	(4,894.0)	(45.0)	(4,939.0)
12.	POST-RETIREMENT TRUE-UP V/A	(5,000.0)	(45.9)	(5,045.9)
13.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A		52.0	52.0
14.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A		150.6	150.6
15.	OPEN BILL SERVICE D/A			0.0
16.	OPEN BILL ACCESS V/A			0.0
17.	UNABSORBED DEMAND COST D/A	13,526.2	181.0	13,707.2
18.	DESIGN DAY CRITERIA TRANSPORTATION D/A	12,839.3	171.3	13,010.6
19.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8		4,435.8
20.	EARNINGS SHARING MECHANISM	(12,650.0)	(113.7)	(12,763.7)
21.	TOTAL	9,237.6	385.2	9,622.8

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**	(1,268.3)	(1,027.4)			(88.0)	(152.8)				
2.	**UNACCOUNTED FOR GAS V/A**	12,025.6			12,025.6						
3.	**STORAGE AND TRANSPORTATION D/A**	(1,164.0)				(425.4)	(738.6)				
4.	**DEFERRED REBATE ACCOUNT**	(3,192.8)			(3,192.8)						
5.	**DEMAND SIDE MANAGEMENT 2013**	0.0							0.0		
6.	**LOST REVENUE ADJ MECHANISM 2013**	0.0							0.0		
7.	**DEMAND SIDE MANAGEMENT INCENTIVE 2013**	0.0							0.0		
8.	**CREDIT FINAL BILL D/A**	(5,538.0)							(5,538.0)		
9.	**ONTARIO HEARING COSTS V/A**	0.0									0.0
10.	**GAS DISTRIBUTION ACCESS RULE D/A 2014**	152.7								152.7	
11.	**AVERAGE USE TRUE-UP V/A**	(4,939.0)							(4,939.0)		
12.	**POST-RETIREMENT TRUE-UP V/A**	(5,045.9)									(5,045.9)
13.	**2014 CUSTOMER CARE CIS RATE SMOOTHING D/A**	52.0								52.0	
14.	**2013 CUSTOMER CARE CIS RATE SMOOTHING D/A**	150.6								150.6	
15.	**OPEN BILL SERVICE D/A**	0.0								0.0	
16.	**OPEN BILL ACCESS V/A**	0.0								0.0	
17.	**UNABSORBED DEMAND COST D/A**	13,707.2					13,707.2				
18.	**DESIGN DAY CRITERIA TRANSPORTATION D/A**	13,010.6					13,010.6				
19.	**TRANSITION IMPACT OF ACCT CHANGE D/A**	4,435.8						0.0			4,435.8
20.	**EARNINGS SHARING MECHANISM**	(12,763.7)						0.0			(12,763.7)
21.	**TOTAL**	9,622.8	(1,027.4)	0.0	8,832.8	(513.4)	25,826.3	0.0	(10,477.0)	355.3	(13,373.8)
	ALLOCATION										
1.1	RATE 1	761.6	(541.4)	0.0	3,766.7	(250.5)	14,535.9	0.0	(7,811.9)	327.3	(9,264.5)
1.2	RATE 6	7,529.7	(432.3)	0.0	3,725.5	(236.0)	10,813.1	0.0	(2,665.1)	27.9	(3,703.5)
1.3	RATE 9	(5.4)	(0.1)	0.0	0.4	0.0	0.1	0.0	0.0	0.0	(5.8)
1.4	RATE 100	8.4	(0.5)	0.0	3.1	(0.1)	8.9	0.0	0.0	0.0	(3.1)
1.5	RATE 110	381.2	(18.8)	0.0	369.9	(6.9)	164.2	0.0	0.0	0.0	(127.2)
1.6	RATE 115	409.7	(2.0)	0.0	377.6	(0.0)	83.8	0.0	0.0	0.0	(49.7)
1.7	RATE 125	(109.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(109.3)
1.8	RATE 135	33.9	(3.4)	0.0	43.9	0.0	0.0	0.0	0.0	0.0	(6.5)
1.9	RATE 145	55.4	(3.8)	0.0	99.2	(3.5)	0.0	0.0	0.0	0.0	(36.5)
1.10	RATE 170	261.0	(10.5)	0.0	318.4	(8.8)	0.0	0.0	0.0	0.0	(38.1)
1.11	RATE 200	301.0	(14.8)	0.0	128.2	(7.6)	220.3	0.0	0.0	0.0	(25.2)
1.12	RATE 300	(4.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.5)
1.		9,622.8	(1,027.4)	0.0	8,832.8	(513.4)	25,826.3	0.0	(10,477.0)	355.3	(13,373.8)

Witnesses: J. Collier
A. Kacicnik
M. Kirk

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	643.7	(516.5)	0.0	3,353.9	(223.1)	12,942.7	0.0	(6,955.7)	291.4	(8,249.0)
	- 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	87.0			251.4	(16.7)	970.3	0.0	(521.5)	21.8	(618.4)
	- WBT	31.0	(24.9)		161.4	(10.7)	622.9	0.0	(334.8)	14.0	(397.0)
RATE 6	- SYSTEM SALES	4,424.9	(343.6)	0.0	2,231.2	(141.3)	6,476.0	0.0	(1,596.1)	16.7	(2,218.0)
	- 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	1,963.0			918.5	(58.2)	2,665.9	0.0	(657.1)	6.9	(913.1)
	- WBT	1,141.9	(88.7)		575.8	(36.5)	1,671.2	0.0	(411.9)	4.3	(572.4)
RATE 9	- SYSTEM SALES	(4.7)	(0.1)	0.0	0.3	0.0	0.1	0.0	0.0	0.0	(5.1)
	- 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	(0.6)			0.0	0.0	0.0	0.0	0.0	0.0	(0.7)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	6.2	(0.4)	0.0	2.3	(0.1)	6.6	0.0	0.0	0.0	(2.3)
	- 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	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	2.2	(0.1)		0.8	(0.0)	2.3	0.0	0.0	0.0	(0.8)
RATE 110	- SYSTEM SALES	56.6	(9.4)	0.0	61.0	(1.1)	27.1	0.0	0.0	0.0	(21.0)
	- 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	268.0			247.8	(4.6)	110.0	0.0	0.0	0.0	(85.2)
	- WBT	56.7	(9.4)		61.1	(1.1)	27.1	0.0	0.0	0.0	(21.0)
RATE 115	- SYSTEM SALES	0.7	(0.1)	0.0	0.7	(0.0)	0.2	0.0	0.0	0.0	(0.1)
	- 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	397.8			364.8	(0.0)	81.0	0.0	0.0	0.0	(48.1)
	- WBT	11.2	(1.9)		12.0	(0.0)	2.7	0.0	0.0	0.0	(1.6)
RATE 135	- SYSTEM SALES	2.2	(0.5)	0.0	3.2	0.0	0.0	0.0	0.0	0.0	(0.5)
	- 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	18.5			21.7	0.0	0.0	0.0	0.0	0.0	(3.2)
	- WBT	13.2	(2.9)		19.0	0.0	0.0	0.0	0.0	0.0	(2.8)
RATE 145	- SYSTEM SALES	5.9	(2.1)	0.0	13.4	(0.5)	0.0	0.0	0.0	0.0	(4.9)
	- 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	44.4			74.5	(2.6)	0.0	0.0	0.0	0.0	(27.4)
	- WBT	5.0	(1.7)		11.3	(0.4)	0.0	0.0	0.0	0.0	(4.2)
RATE 170	- SYSTEM SALES	18.5	(4.1)	0.0	26.5	(0.7)	0.0	0.0	0.0	0.0	(3.2)
	- 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	213.5			250.3	(6.9)	0.0	0.0	0.0	0.0	(30.0)
	- WBT	29.0	(6.4)		41.6	(1.1)	0.0	0.0	0.0	0.0	(5.0)
RATE 200	- SYSTEM SALES	221.3	(14.8)	0.0	95.9	(5.7)	164.7	0.0	0.0	0.0	(18.8)
	- 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	79.7			32.4	(1.9)	55.6	0.0	0.0	0.0	(6.3)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		(109.3)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(109.3)
RATE 300		(4.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.5)
		9,622.8	(1,027.4)	0.0	8,832.8	(513.4)	25,826.3	0.0	(10,477.0)	355.3	(13,373.8)

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	0.0134	(0.0108)	0.0000	0.0700	(0.0047)	0.2701	0.0000	(0.1452)	0.0061	(0.1722)	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	0.0242			0.0700	(0.0047)	0.2701	0.0000	(0.1452)	0.0061	(0.1722)	0.0000
	- WESTERN T-SERVICE	0.0134	(0.0108)		0.0700	(0.0047)	0.2701	0.0000	(0.1452)	0.0061	(0.1722)	0.0000
RATE 6	- SYSTEM SALES	0.1388	(0.0108)	0.0000	0.0700	(0.0044)	0.2032	0.0000	(0.0501)	0.0005	(0.0696)	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	0.1496			0.0700	(0.0044)	0.2032	0.0000	(0.0501)	0.0005	(0.0696)	0.0000
	- WESTERN T-SERVICE	0.1388	(0.0108)		0.0700	(0.0044)	0.2032	0.0000	(0.0501)	0.0005	(0.0696)	0.0000
RATE 9	- SYSTEM SALES	(0.9517)	(0.0108)	0.0000	0.0700	0.0000	0.0104	0.0000	0.0000	0.0002	(1.0215)	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	(0.9409)			0.0700	0.0000	0.0104	0.0000	0.0000	0.0002	(1.0215)	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
RATE 100	- SYSTEM SALES	0.1907	(0.0108)	0.0000	0.0700	(0.0021)	0.2032	0.0000	0.0000	0.0000	(0.0696)	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	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.1907	(0.0108)		0.0700	(0.0021)	0.2032	0.0000	0.0000	0.0000	(0.0696)	0.0000
RATE 110	- SYSTEM SALES	0.0649	(0.0108)	0.0000	0.0700	(0.0013)	0.0311	0.0000	0.0000	0.0000	(0.0241)	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	0.0757			0.0700	(0.0013)	0.0311	0.0000	0.0000	0.0000	(0.0241)	0.0000
	- WESTERN T-SERVICE	0.0649	(0.0108)		0.0700	(0.0013)	0.0311	0.0000	0.0000	0.0000	(0.0241)	0.0000
RATE 115	- SYSTEM SALES	0.0655	(0.0108)	0.0000	0.0700	(0.0000)	0.0155	0.0000	0.0000	0.0000	(0.0092)	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	0.0763			0.0700	(0.0000)	0.0155	0.0000	0.0000	0.0000	(0.0092)	0.0000
	- WESTERN T-SERVICE	0.0655	(0.0108)		0.0700	(0.0000)	0.0155	0.0000	0.0000	0.0000	(0.0092)	0.0000
RATE 135	- SYSTEM SALES	0.0488	(0.0108)	0.0000	0.0700	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0104)	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	0.0596			0.0700	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0104)	0.0000
	- WESTERN T-SERVICE	0.0488	(0.0108)		0.0700	0.0000	0.0000	0.0000	0.0000	0.0000	(0.0104)	0.0000
RATE 145	- SYSTEM SALES	0.0310	(0.0108)	0.0000	0.0700	(0.0025)	0.0000	0.0000	0.0000	0.0000	(0.0258)	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	0.0418			0.0700	(0.0025)	0.0000	0.0000	0.0000	0.0000	(0.0258)	0.0000
	- WESTERN T-SERVICE	0.0310	(0.0108)		0.0700	(0.0025)	0.0000	0.0000	0.0000	0.0000	(0.0258)	0.0000
RATE 170	- SYSTEM SALES	0.0489	(0.0108)	0.0000	0.0700	(0.0019)	0.0000	0.0000	0.0000	0.0000	(0.0084)	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	0.0597			0.0700	(0.0019)	0.0000	0.0000	0.0000	0.0000	(0.0084)	0.0000
	- WESTERN T-SERVICE	0.0489	(0.0108)		0.0700	(0.0019)	0.0000	0.0000	0.0000	0.0000	(0.0084)	0.0000
RATE 200	- SYSTEM SALES	0.1616	(0.0108)	0.0000	0.0700	(0.0042)	0.1202	0.0000	0.0000	0.0000	(0.0137)	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	0.1724			0.0700	(0.0042)	0.1202	0.0000	0.0000	0.0000	(0.0137)	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:												
RATE 125	- All	(1.0999)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(1.0999)	0.0000
	- Customer-specific **											0.0000
RATE 300	- All	(29.1595)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(29.1595)	0.0000
	- Customer-specific **											

Notes:
* Unit Rates derived based on 2014 actual volumes

Witnesses: J. Collier
A. Kacicnik
M. Kirk

Enbridge Gas Distribution Inc.
2014 Deferral and Variance Account Clearing
Bill Adjustment in October 2015 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	2,400	0.0134	0.0242	0.0134	0.3	0.6	0.3
2.1	**RATE 6 COMMERCIAL**							
2.2	General Use	43,285	0.1388	0.1496	0.1388	60	65	60
	CONTRACT SERVICE							
3.1	**RATE 100**							
3.2	Industrial - small size	339,188	0.1907	0.0000	0.1907	647	-	647
4.1	**RATE 110**							
4.2	Industrial - small size, 50% LF	598,568	0.0649	0.0757	0.0649	389	453	389
4.5	Industrial - avg. size, 75% LF	9,976,121	0.0649	0.0757	0.0649	6,478	7,553	6,478
5.1	**RATE 115**							
5.2	Industrial - small size, 80% LF	4,471,609	0.0655	0.0763	0.0655	2,931	3,413	2,931
6.1	**RATE 135**							
6.2	Industrial - Seasonal Firm	598,567	0.0488	0.0596	0.0488	292	357	292
7.1	**RATE 145**							
7.2	Commercial - avg. size	598,568	0.0310	0.0418	0.0310	186	250	186
8.1	**RATE 170**							
8.2	Industrial - avg. size, 75% LF	9,976,121	0.0489	0.0597	0.0489	4,880	5,955	4,880

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

STATUS UPDATES

1. Within the EB-2012-0459 Decision, the Board indicated various annual reporting requirements which were either proposed or agreed to by the Company and also further requirements determined by the Board. The evidence location and status of each of such items is described in the following paragraphs.

2. The Decision highlighted that Enbridge proposed and would be required to file annually a Productivity Report within its ESM Application and to provide a Status Report of a required Benchmarking Study which is to be filed at the end of the Custom IR term. The Productivity Report is found at Exhibit D, Tab 2, Schedule 1 and the Status of the Benchmarking Study is found at Exhibit D, Tab 1, Schedule 5.

3. The Decision highlighted that Enbridge agreed to annually provide the same information as Union Gas provides in relation to section 12.1 of the Union Gas 2014-2018 Settlement Agreement, and also to provide the same RRR filings as Union Gas files, such as SQR results. All of that information is provided in this application within the B-series of Exhibits, the C-series of Exhibits, within Exhibit D, Tab 5, Schedule 1 and within Exhibit D, Tab 6.

4. Enbridge also agreed to hold an Annual Stakeholder Day each year during the Custom IR term. Enbridge held its first Stakeholder Day on April 1, 2015 and the materials presented that day are filed in evidence at Exhibit D, Tab 3, Schedule 1.

5. The Decision also required Enbridge to report annually on the status of major projects such as the GTA and WAMS, on the progress of the System Integrity Program, on the progress of an updated Asset Management Planning process and

to report on and provide a Gas Supply Planning Memorandum. Information on each of these requirements is found in evidence at;

- GTA – Exhibit D-1-2
- WAMS – Exhibit D-1-3
- System Integrity – Exhibit D-1-4
- Asset Management Plan – Exhibit D-1-6
- Gas Supply Memorandum – Exhibit D-4-1

STATUS OF GTA PROJECT

1. Within the EB-2012-0459 Custom IR Decision (pg. 81), the Board indicated that Enbridge was to report on the status, progress and cost versus schedule of the GTA project.

2. Enbridge provided such information at the April 1, 2015 Stakeholder Day. (please see pages 20 to 30 of the Stakeholder Day materials found at Exhibit D, Tab 3, Schedule 1)

3. As indicated at the Stakeholder Day, the project has experienced some timing delays due to the complexity of permiting in urban areas. The pipeline is currently anticipated to be complete and in service by Q4, 2015 with some residual restoration and closeout costs to occur in 2016.

4. Some siting issues have also been experienced which will delay the installation of the Buttonville and Jonesville stations. More details on the specific issues, and related impacts, will be provided to the Board in the near future.

5. The actual costs incurred versus forecast as at December 31, 2014 were $172.4 million versus the forecast of $226.3 million approved by the Board. This was due to the deferral of construction activities and the delivery of the NPS 42 mainline pipe to 2015. Additionally lower land and land rights, labour, project overheads, and IDC were incurred than forecast in 2014.

6. The current approximate forecast of costs remaining to complete the project are approximately $583.6 million, for a total project cost of $756 million. This is higher than the forecast total project cost of $686.5 million that was presented to the Board.

Witnesses: S. Dodd
O. Schneider

7. The 2015 cost variance is driven by the shift of major construction activities into 2015. The delivery of the NPS 42 mainline pipeline was shifted to 2015 as well. Further, the cost of facilities and mainline construction contracts were higher than forecast. These contracts, although bid through competitive RFP processes, experienced cost escalation due to market conditions. The anticipated future construction cost variances are mostly due to delays in permits and land acquistions.

Witnesses: S. Dodd
O. Schneider

STATUS OF WAMS PROJECT

1. Within the EB-2012-0459 Custom IR Decision (pg. 81), the Board indicated that Enbridge was to report on the status, progress and cost versus schedule of the WAMS project.

2. Enbridge provided such information at the April 1, 2015 Stakeholder Day. (Please see pages 31 to 36 of the Stakeholder Day materials found at Exhibit D, Tab 3, Schedule 1)

3. As indicated at the Stakeholder Day, the project has experienced some timing delays mainly due to the length of time required to conclude on the competitive bid processes for first, the Technology, and then subsequently for the System Integrator. The project is expected to progress through 2015 and is anticipated to be in service by the end of Q1, 2016, with a stabilization and warranty period to follow. This is slightly later than the intitial forecast that WAMS would go live by the end of 2015, which now results with the transition from Envision continuing into 2016.

4. The actual costs incurred as at December 31, 2014 were $19.6 million versus the cumulative forecast of $36.8 million to the end of 2014 that was presented in the EB-2012-0459 proceeding. The current approximate forecast of costs remaining to complete the project is approximately $60 million, for a total cost of approximately $80 million. This is somewhat higher than the $70.6 million forecast of total costs presented in the EB-2012-0459 proceeding. There currently is a degree of uncertainty with the remaining forecast at this point of time as the Company is in final negotiations for a Fixed Fee contract for the Construct Phase.

5. The cost variances to date are mostly the result of timing delays due to the competitive bid processes – this delayed some of the spending that was forecast for 2014. The anticipated future cost variances are mostly due to the greater level of detail now understood as a result of the Design Phase. It is now more complex then originally anticipated and will result in increased resource effort.

STATUS OF SYSTEM INTEGRITY PROGRAM

1. Within the EB-2012-0459 Custom IR Decision (pg. 81), the Board indicated that Enbridge was to report on the status and expenditures for the System Integrity Program.

2. In the Decision, the Board approved Enbridge's forecasts of required capital expenditures for each of the 2014 through 2018 fiscal years. With respect to the System Integrity Program the Board indicated its concerns about uncertainty and lack of external evidence in relation to the program drivers and estimates. The Board indicated that it expected these concerns to be addressed through future refinements within Enbridge's Asset Management Planning and Benchmarking processes. In the meantime, the Board required Enbridge to report annually on the status and expenditures of System Integrity Program.

3. Enbridge's System Integrity and Reliability program remains a key priority for the Company in terms of understanding and proactively mitigating potential threats to the distribution system. The Company undertook many initiatives in 2014 to continue to address known issues and proactively maintain a safe and reliable distribution and storage system.

4. As shown below within Table 1, Enbridge's actual System Integrity spend within 2014 was $125.9 million versus the $132.3 million which the Board approved within the EB-2012-0459 proceeding.

Witnesses: D. Broude
D. Lapp

ASSET CATEGORY	2014 ACT	2014 IRM	2014 VARIANCE
MAINS	32,093	24,594	7,499
SERVICES	20,661	21,128	(467)
GATE/DISTRICT/HEADER STATIONS	12,690	23,990	(11,301)
METERS/RECORDS MGT/ ENVISION EXT	42,142	41,808	334
SIR DIRECT RESOURCE COSTS	18,347	20,813	(2,466)
Grand Total	**125,933**	**132,333**	**(6,400)**

5. The Company continues to evaluate System Integrity program work relative to the anticipated requirements as outlined in the EB-2012-0459 proceeding. Where there are changes in circumstances such as delays in readiness by third parties, or land acquisition issues, or as more current information becomes known, Enbridge may be required to re-prioritize originally anticipated program work.

6. The $6.4 million under spend variance represents a 4.8% variance versus the approved budget of $132.3 million. The main contributors to the variance are higher spending within the mains replacement category and lower spending within the stations category.

7. The higher mains replacement category spend was mostly the result of additional spending on the Innes Road LTC. Originally, this had been planned as a retrofit project for pipeline with SMYS above 30%, but upon doing in-line inspection it was determined that the line needed to be re-laid.

8. The lower stations category spend was mostly the result of the temporary deferral of some anticipated stations work such as the Cookstown gate station and the Keele/Finch feeder station replacement due to delayed land acquisition at the Cookstown site and work by the TTC at the Keele/Finch station project.

9. The System Integrity Direct Resource Cost was lower than forecast, in part as a result of the Company's efforts to manage and reduce FTE additions, as described in the Productivity Initiatives Summary (Exhibit D, Tab 2, Schedule 1).

10. While there have been variances due to changes in required work during 2014 it is expected that System Integrity and Reliability program costs in 2015 will be at or higher than the 2015 OEB approved levels.

Witnesses: D. Broude
D. Lapp

STATUS OF BENCHMARKING STUDY

1. Within the EB-2012-0459 Custom IR Decision (pg. 81), the Board indicated that Enbridge was to report on an annual basis, the progress on the benchmarking study (capital and O&M) which Enbridge is required to file within the 2019 re-basing rate application, including reporting on stakeholder consultation and independent third-party involvement.

2. Enbridge provided a brief outline of the status of the benchmarking study requirements at the April 1, 2015 Stakeholder Day. (Please see page 82 of the Stakeholder Day materials found at Exhibit D, Tab 3, Schedule 1)

3. Later within its fiscal year 2015, the Company will be engaging its stakeholders in preparation of commencing a consultative to review and provide feedback on the required and planned benchmarking study it will be undertaking to address required capital and operating costs.

4. The consultation results will be used within the development of a benchmarking study which will be filed within a 2019 re-basing rate application and will be supported by an independent expert opinion.

Witnesses: K. Culbert
I. Macpherson
M. Suarez

ASSET MANAGEMENT

Background

1. In its Decision with Reasons related to EB-2012-0459, the Board provided feedback to Enbridge regarding the Company's approach to Asset Management, which can be characterized in one word as: insufficient. The Board was clear in its view that robust asset management planning at Enbridge should:

   - Include all the Company's assets, and
   - Be based upon a comprehensive process of condition assessment, risk evaluation, and prioritization

   Furthermore, the Board noted that an asset plan should:

   - Be the vehicle to perform rationalization, prioritization, and optimization, and
   - Be directly linked to the budget

Overview

2. In response to the Board's feedback, the Company has initiated steps to implement a formal Asset Management ("AM") system, with an aspirational goal of compliance with ISO 55000 (Standard for Asset Management - released January 15, 2014). AM is defined as optimally and sustainably managing assets, their performance, risks and costs over their lifecycle for the purpose of achieving the organization's strategic plan[1]. Enbridge is also cognizant of the need to be mindful of ratepayer

[1] PAS 55-1:2008 Asset Management Part 1: Specification for the Optimized Management of Physical Assets, British Standards Institute, page V, section 0 Introduction, sub-section 0.1 What is Asset Management?

impacts and to incorporate that perspective when considering the balance between performance, risk, and costs as it optimizes its asset plan.

Approach

3. The Company is implementing changes and improvements in a staged approach in three primary phases:

Phase 1: Enabling Changes – consists of designated roles and accountabilities, direct linkage of performance, risk and cost, improvements to overall risk management, an Asset Investment Planning decision support tool, and implementation of supporting processes & tools necessary to facilitate change. This phase is in progress and on track for its primary deliverable: a step change improvement to the 2016 budget capital planning process for gas carrying assets.

Phase 2: Supporting Changes – consists of improvements to Asset Analytics data, tools, processes, and capabilities, creation and adoption of a living 10-year asset management plan, consideration of both Capital and O&M, and inclusion of all assets (addition of Fleet, IT, Facilities). Initial planning has begun and transition to Phase 2 is expected to commence September 2015 with substantial completion by end 2016.

Phase 3: Sustaining Changes– consists of all supporting improvements necessary to sustain the AM system over time and to demonstrate full ISO 55000 compliance, such as audit, continuous improvement, and management of change. This phase is expected to be complete by the end of 2017.

Progress

4. The Company has appointed a Director of Asset Management and assembled a dedicated project team to help the business implement and transition to operating within a formalized asset management system. The Company has divided its gas carrying assets into four primary classes: Storage, Pipe, Stations, and Customer. Each class has a designated Asset Class Director with visibility into all existing and proposed expenditures associated with the lifecycle of all individual assets within the class.

5. Each Asset Class Director is supported by a corresponding Asset Manager (and sub-class managers) who are focal points for all work associated with their asset class and will use their deep understanding of the assets and their condition to identify issues and generate possible solutions. As the focal point, the Asset Managers receive support from other functions including reliability engineering, risk assessment, asset analytics, and network analysis.

6. The Company has strengthened its risk assessment group, rewritten its risk register process, and drafted an Operational Risk Assessment Standard based upon best practices, which includes an underlying goal of transparency.

7. In addition, Enbridge has procured an Asset Investment Planning tool and is in the implementation phase with a planned Go-Live date of July 31st 2015. Planning for Phase 2 - Asset Analytics improvements has also begun.

Independent 3rd Party Assessment

8. The Board also noted its desire for 3rd party independent review of the Company's approach to asset management and its resulting plans. Enbridge anticipates

engaging a 3rd party to independently review its AM system and processes starting in the fall of 2015. The Company envisions a multiyear engagement wherein the reviewer will report annually, or more frequently, on the progress made, culminating in a final report. Inputs to the plan, and the plan itself, will also be tested through independent review. At this point, Enbridge has not determined whether the two types of review should be combined or separated, and will make a future decision once it better understands the capabilities of potential reviewers.

ANNUAL PRODUCTIVITY REPORT

Introduction

1. The purpose of this evidence is to present the 2014 Productivity Report as part of the performance measurement framework required by the Board in its July 17, 2014 Decision with Reasons for EB-2012-0459. This framework is comprised of two reporting mechanisms: the Annual Productivity Report, and the Benchmarking Report which will be provided at the end of the 2014 to 2018 Custom IR term.

2. The status of the Benchmarking Report is set out at Exhibit D, Tab 1, Schedule 5.

3. Within this document, Enbridge addresses the following:

   (i) In its Custom IR Application, Enbridge identified productivity savings that it would have to achieve during the IR term;

   (ii) In the Custom IR Decision, the Board approved Enbridge's capital and O&M budgets for future years, but required reporting of the Company's productivity initiatives relative to what was identified in Enbridge's evidence;

   (iii) Enbridge has made productivity improvements a strong focus during the Custom IR term;

   (iv) During the first year of the Custom IR term, Enbridge has found ways to achieve some, but not all of the productivity savings targets identified in the Custom IR evidence;

   (v) Enbridge has also found other productivity savings, including some spending reductions;

(vi) In total, productivity savings during the first year of the Custom IR term are less than anticipated, but work will continue to find ongoing opportunities;

(vii) Enbridge's performance metrics show that it continues to offer safe, reliable, customer-centered service.

Background

4. In the 2013 Test Year Settlement Agreement (EB-2011-0354, Exhibit N1, Tab 1, Schedule 1, p. 40), the Company acknowledged stakeholders' expectations for the tracking and reporting of productivity and efficiency gains on an initiative basis in addition to, the benchmarking concept mentioned above over the next IR term. The Company proposed a performance measurement framework in its Custom IR application (EB-2012-0459, Exhibit A2, Tab 11, Schedule 2) which would provide visibility into the Company's efforts in implementing sustainable Productivity initiatives and a mechanism to communicate performance and outcomes during the course of the IR term.

5. Like many other utilities in North America, Enbridge's investment requirements are increasing as it seeks to replace aging infrastructure, reduce risk, and enhance the overall capability of the system to ensure safety and reliability of service. In addition, energy consumption is leveling off from more efficient use of natural gas and the success of Demand-Side Management ("DSM") conservation programs. However, unlike many other jurisdictions, Enbridge continues to see growth on its system, necessitating it to continue incurring increasing costs to provide service. This challenge can be effectively addressed through meaningful productivity improvements.

6. To hold itself to this commitment, the Company embedded reductions into the Company's proposed O&M and Capital forecasts from 2014 to 2018. Although no specific initiatives were in place for these areas, known cost pressures compelled the Company to look for opportunities to allay costs in these or other areas. Ratepayer cost relief was built into the baseline costs, and not merely set as a target over the course of the 5-year period. The relative ability to achieve these savings had to be balanced against other areas while more complex solutions are being considered in the targeted areas.

7. Similarly for Other O&M (which excludes Customer Care/CIS, DSM, Pension/OPEBs), productivity savings have been embedded in cost forecasts by not including known and expected cost increases and by keeping FTEs flat for the duration of the IR plan. For areas with identified cost pressures, the intent was to closely manage these and other cost areas to be able to absorb these unmitigated cost pressures so as to stay within the budget parameters.

8. The Board accepted the proposed capital expenditures as submitted as well as the 2014 level of O&M. In addition, it adjusted the 2014 O&M level upward by 1% in 2015 and in each subsequent year to 2018 "to ensure that the budget constraints are sufficient to drive an appropriate level of efficiency and that the result is genuine productivity improvements and not merely short-term cost cutting" (EB-2012-0459 Decision, p. 47).

9. Tables 1 and 2 show the Core Capital and Other O&M amounts approved. Productivity commitments in the form of embedded productivity savings and excluded variable capital costs are similarly shown.

Table 1:

Capital Amounts Approved						
	2014	2015	2016	2017	2018	Total IR Term
Core Capital without Productivity	495.1	538.3	544.9	527.1	537.2	2,642.7
Less: Embedded Savings	(26.2)	(28.7)	(27.1)	(35.2)	(45.3)	(162.5)
Less: Variable Costs	(25.1)	(63.0)	(75.9)	(50.0)	(50.0)	(264.1)
Approved Core Capital Expenditures	443.8	446.6	441.9	441.9	441.9	2,216.1

Table 2:

Other O&M Amounts Approved						
	2014	2015	2016	2017	2018	Total IR Term
Proposed "Other" O&M	252.1	261.6	276.6	287.8	299.5	1,377.6
Less: Embedded Savings	(24.1)	(30.1)	(35.6)	(39.3)	(43.2)	(172.3)
Less: OEB Adjustment	-	(1.2)	(8.4)	(13.6)	(19.0)	(42.2)
Approved "Other" O&M	228.0	230.3	232.6	234.9	237.3	1,163.1

10. Further, in its Decision, the Board noted that:

> Enbridge did not specifically identify the initiatives and programs that it intends to employ in order to achieve these productivity savings. The Board will require Enbridge to report on the status of the work items making up the $162 million embedded productivity savings well as those items making up the $264 million variable costs … as part of its annual reporting process (p. 36).

The reporting will identify whether and how these work items were accommodated within the approved capital amount. This approach and the associated level of transparency will assist the Board in monitoring the operation of Enbridge's Custom IR and will provide Enbridge with an incentive to meet its budgets through productivity improvements.

11. This evidence will include the work items, initiatives, and programs implemented by the Company in 2014 to deliver on the embedded savings of $50.3 million

Witnesses: I. Macpherson
M. Suarez

($26.2 million in capital and $24.1 million in O&M). It will describe the excluded variable capital costs ($25.1 million) which were uncertain cost requirements excluded from the proposed capital amount. It will also provide an update to the previously identified potential initiatives in the Custom IR evidence. Leading up to those details, the evidence will first provide some background on the foundational approach.

12. This evidence is structured as follows:

    (i) Enbridge's Focus on Productivity

    (ii) Embedded O&M and Capital Savings

    (iii) Incremental Productivity Initiatives

    (iv) Excluded Variable Capital Costs

    (v) Summary and Sustainability of Savings

    (vi) Performance Measures

<u>Enbridge's Focus on Productivity</u>

13. In its Custom IR Application, the Company included third-party evidence that confirmed Enbridge's successful achievement of productivity relative to other utilities. The Company recognizes that in spite of productivity initiatives taken previously, ultimately, there can be a natural tendency to return to old habits, cultural mindsets, and ingrained practices. Without an ongoing focus and commitment, productivity gains can be undermined and eventually lost.

14. The Company has affirmed this commitment for the Custom IR term. In addition to the embedded productivity commitments that formed the baseline of the Company's operating costs, incremental productivity initiatives are needed to harness the ideas of all employees within the organization. To make significant, measurable progress, the Company believes it is necessary to involve all levels of personnel so that productivity is a collective commitment and a shared objective.

15. To facilitate adoption of the productivity mindset, the Company provided key messages as well as instituted governance and oversight. Together with focused leadership, the foundational messages and personal commitment help contribute to an environment that is top-of-mind for employees to be driven to actively identify opportunities and to adapt to change. The Company sought to galvanize support at all levels with messaging that emphasizes the need to drive productivity improvements.

16. The following productivity guidelines were communicated:

    (i) Productivity comprises the incremental changes which allow employees (1) to deliver the same quality or level of service at lower cost (input, effort, resources), or (2) to enhance the quality of service at the same cost (input, effort, resources). Productivity actions are incremental actions to those that underpinned the original costs which were included in the Custom IR application.

    (ii) Productivity actions should be sustainable, assuming no change to operating requirements.

    (iii) Employees were encouraged to "do things smarter" and "do things right the first time", and to focus on activities that add the most value.

(iv) No materiality thresholds were established; all productivity savings reported were captured.

(v) Productivity would mostly be achieved within the current parameters of what was approved (services, channels of cost recovery, etc.).

17. By focusing on the service/output, employees and management were able to rationalize actions that did not add value and achieve savings, or actions that needed to be strengthened and made more targeted to be more effective.

Embedded O&M and Capital Savings (Productivity)

18. Embedded productivity savings represent the anticipated cost pressures that were eliminated or held flat within the capital and O&M budgets filed in the Custom IR proceeding as guaranteed savings which serve as a productivity assurance to ratepayers. Although the Company was aware of the challenge of delivering to this commitment, the up-front cost reduction forced it to seek efficiencies that would mitigate those cost pressures or find savings elsewhere.

19. Tables 3 and 4 list the embedded productivity savings or reductions in 2014 O&M and Capital that were described in evidence and testimony provided at the EB-2014-0459 proceeding for the 2014 - 2018 Custom IR Rate Application. The detailed list was provided as an undertaking at the hearing to summarize the productivity savings embedded in the Company's forecasts (EB-2012-0459, Exhibit J1.6).

Table 3:

2014 Embedded O&M Savings	
	($M)
Merit increase	(1.2)
Employee Benefits	(2.1)
Incremental cost to service new customers	(1.5)
Incremental safety and integrity work	(8.9)
External contractor rate increases	(0.3)
Increased volume of locates-compliance with Bill 8	(2.6)
Capped FTEs	(2.8)
Bad Debt expenses	(4.7)
Total O&M Productivity Guarantee	(24.1)

Table 4:

2014 Embedded Capital Savings	
	($M)
Customer Attachments	(25.9)
Departmental Labour	(0.3)
Total	(26.2)

20. The following paragraphs will describe Enbridge's actions which allowed it to deliver savings and how results compared to the embedded cost reduction targets. The savings are costs Enbridge would have otherwise incurred. While Enbridge found productivity savings, it was not able to achieve all savings targets identified.

21. Merit increases were budgeted on the basis of a 2% increase in annual salaries although 3% increases were believed to be necessary to remain competitive (EB-2012-0459 Reply, p. 92). Actual 2014 results had a weighted increase of 2.5% in an effort to balance financial pressures and the Company's competitive position

in the market. Total savings for merit increase was about $0.8 million which was short of the $1.2 million embedded reduction for 2014.

22. Benefit costs continue to rise and are still expected to increase at the projected rate of 6% per year. The approved budget reflected an increase of only 2%. Although actual spending was higher than budget, it was below the expected rate of increase, allowing savings of $1.3 million. The Company remains committed to managing to the lower rate of increase and has made changes to the benefits program effective January 2015. These changes include lifetime maximums, benefit credits based on salaries at January 1st with no further increases throughout the year, mandatory generic drug substitutions, dispensing fee caps, and pre-authorization on some drug categories.

23. Incremental costs to service new customers represent the costs to carry out Fuel Safety Branch Inspections ("FSBI") which are required when gas is introduced to a premise for the first time. These costs were higher than were budgeted as a result of delayed policy changes which should have reduced the need for multiple visits to customer premises. Costs exceeded the embedded reduction by $0.4 million.

24. Incremental safety and integrity work encompasses projects carried out by the Pipeline Integrity & Engineering ("PI&E") and Operations groups. O&M efficiencies associated with the performance of in-line inspections for leaks, corrosion, and damage prevention were achieved through the use of new vendors, new technologies, innovative system operations, and resource efficiencies. In 2014, those improvements and efficiencies resulted in savings of $1.2 million. In addition, Hydrovac scheduling efficiencies and targeted Quality Control of contractor work reduced unnecessary repeat calls, achieving about $2.0 million in cost reductions.

25. By centralizing the oversight of contract management functions, the Company has generated external contractor savings estimated at $0.3 million in 2014.

26. The passage of Bill 8 has imposed significant cost pressures on the Company to manage costs associated with incremental locate volumes. While locate volumes were expected to increase by 6%, productivity savings were embedded within the 2014 O&M budget by increasing locate budgets by only 2.2% in 2014. In fact, volumes increased by about 13% in 2014, directly contributing to a proportional increase in costs.

27. To counter this pressure, Damage Prevention continued with heightened governance and introduced initiatives to reduce O&M costs. Damage Prevention increased the number of Alternative Locate Agreements ("ALAs") by 50% to improve locate efficiency and reduce the cost of carrying out standard field locates. In addition, Damage Prevention increased participation in the Locate Alliance Consortium ("LAC") to further realize savings through locate contracts. These initiatives have resulted in savings of $0.4 million in 2014.

28. A key industry benchmark measuring Damage Prevention program effectiveness is the Damage per 1000 Locates metric. Damage Prevention demonstrated continuous improvement by reducing the measure from 2.8 in 2013 to 2.5 in 2014 representing an 11% decrease. Over the past ten years, this ratio has declined from 11.1 in 2004 to its current standing. The Company continues to be committed to safety improvements by reducing damages through a financially prudent and cost-effective approach.

29. By year-end, FTEs were lower than the 2014 budgeted amount of 2,377 by 140 positions. Departmental Labour Costs that were capitalized were similarly managed. The combination of these efforts resulted in O&M and capital savings in excess of $8.5 million.

30. Bad debt expense was held flat at $9.5 million within the 2014 O&M budget, although indications were that this expense would be around $14.2 million on the basis of weather expectations, commodity forecasts, and the overall level of consumer indebtedness. Actual 2014 bad debt expenses were $12.1 million. While bad debt exceeded the budgeted amount by $2.6 million, savings of $2.1 million was achieved.

31. Embedded productivity commitments in the area of Customer Attachment capital were not met in 2014. Customer Attachment capital was overspent due to the actual mix and geographical distribution of customers, higher municipal fees, material costs, labour market conditions, and the timing of projects. Growth in residential replacement customers, especially in the Ottawa region, has created upward pressure on costs due to the rural and rocky conditions in that franchise area. Similarly, since 2013, municipal fees have increased by 69%, material costs by 32%, and pipeline contractor labour costs per customer have been rising significantly since 2012. Additionally, winter construction has been on the rise, forcing construction costs higher on account of winter premiums charged by contractors.

32. To help mitigate these pressures, the Company is signing long-term construction contracts to achieve cost certainty over a longer time horizon. It is also looking to manage the timing of construction projects to avoid winter premiums.

33. Table 5 details the estimated savings for each embedded productivity area in O&M and Capital, respectively.

Table 5:

	2014 Estimated Savings Relative to Embedded O&M and Capital Reductions		
		Embedded ($M)	**Estimated ($M)**
1.	O&M: Merit increase	(1.2)	(0.8)
2.	O&M: Employee Benefits	(2.1)	(1.3)
3.	O&M: Incremental cost to service new customers	(1.5)	0.4
4.	O&M: Incremental safety and integrity work	(8.9)	(3.2)
5.	O&M: External contractor rate increases	(0.3)	(0.3)
6.	O&M: Increased volume of locates-compliance with Bill 8	(2.6)	(0.5)
7.	O&M: FTEs (includes capitalized labour amounts*)	(3.1)	(8.5)
8.	O&M: Bad Debt expenses	(4.7)	(2.1)
9.	Total Estimated O&M Savings (including capitalized labour*	(24.4)	(16.2)
10.	Capital: Customer Attachments	(25.9)	(0.2)
11.	Total Estimated Embedded O&M & Capital	(50.2)	(16.4)
	** Embedded Capitalized Labour savings of 0.3 million.*		

34. Of the $24.1 million guaranteed O&M savings as shown in Table 3 and the capitalized Departmental Labour Costs in Table 4 of $0.3 million, cost mitigation efforts achieved $16.2 million most effectively through FTE management.

35. Capital savings from reduced Customer Attachment costs were largely unsuccessful. However, total capital savings in all Core Capital expenditure areas exceeded $28 million in 2014 which more than offset the challenges in Customer Attachment. The capital expenditures for 2014 are detailed within Exhibit B, Tab 2, Schedule 4 (Comparison of Utility Capital Expenditures) and Exhibit D, Tab 1, Schedule 4 (System Integrity Program).

36. Capital savings were measured relative to the overall Core Capital budget that was approved. The savings result from a combination of prioritization, changes in timing and scope (based on evaluation of alternatives), and efficiencies. To the extent that savings from any of these drivers enabled the inclusion of other capital projects to ensure the capital budget was optimized, these savings are a result of the most efficient allocation and use of capital resources. To that end, some of the capital reductions were considered productivity improvements. However, savings are largely due to one-off circumstances to optimize one-time opportunities identified through ongoing review of the most current information, and through challenges being issued to internal business owners to find the most effective ways to respond to the Company's ongoing requirements. In future, as described at Exhibit D, Tab 1, Schedule 6, prioritization and re-evaluation of the capital portfolio will be heavily informed by the Asset Management process.

37. By managing to a fixed capital budget under increasing cost pressures, the Company attained productivity savings in 2014 by delivering its operational requirements and commitments within the approved amount. Savings of $28.7 million was achieved relative to the total capital budget. Savings in the form of carrying cost reductions could not be extrapolated in advance of the determination of actual amounts in the capital structure. Actions that resulted in reduced FTEs were captured as capital savings to the extent that those positions were budgeted as capitalized. Savings are expressed inclusive of salaries, benefits, etc.

<u>Incremental Productivity Initiatives</u>

38. Productivity actions or initiatives that go beyond the items set out in Table 5 were pursued in all areas of the Company, across all levels of employees.

39. Productivity initiatives were tracked centrally to ensure consistency in the application of productivity criteria and the measurement of results. To the extent that savings were realized relative to budget amounts through incremental changes to the way work was carried out, and were sustainable, the action was captured as a productivity initiative.

40. Other actions considered to be prudent business decisions that were made to take advantage of specific opportunities to enable future cost savings (although not originally identified in the budget) were considered to be avoided costs, but not productivity actions. There were also one-time opportunities for savings that were pursued but were not considered repeatable or sustainable. Such actions enabled the Company to achieve deeper savings than what would have been the case with embedded productivity savings and incremental initiatives alone. All such actions were not considered to qualify as productivity examples, and as such lie outside the scope of this report yet contribute to the overall positive financial and performance results in 2014.

41. Close to one hundred productivity initiatives were identified throughout the organization. A number of initiatives described the changes in allocation of work within departments, enabling FTE reductions which are captured in the embedded productivity savings reported for FTEs. Other initiatives identified will only show productivity savings in 2015. Most of the initiatives involved changes in workflows which enabled efficiencies or improvements in computing tools and processes by streamlining procedures. Although these are valid productivity improvements, the benefits can only be measured through time studies that compare the status quo to the change implemented. Further, without a clear understanding of the labour capacity freed-up by the efficiency that could have resulted in bottom line savings

through FTE optimization, such initiatives are tracked as indicators of savings in future years but not included in this report. Ultimately, only initiatives that were determined to have sustainable and measurable productivity savings are reported herein. They are grouped into the following categories:

(i) Labour Optimization

(ii) Process Optimization

(iii) Materials/Space/Equipment Rationalization

(iv) Policy Changes and Improvements

42. In addition to the $8.5 million in FTE reductions (both O&M and capital) identified in the earlier part of this evidence, other labour optimization efforts were pursued that enabled the shedding of costs through the absorption of work by existing labour capacity, the reallocation of tasks, the targeted hiring of specific skill sets to offset outside services, and the management of overtime hours. The savings from these types of initiatives were estimated at $0.6 million.

43. Process Optimization initiatives relate to changes in the way work was organized to achieve efficiencies. These included system changes, more efficient work flows, streamlined tools, and the elimination of redundant reports. For the most part, achieved savings were not through cost reductions, but through the release of labour capacity to absorb other work. These particular savings could not be measured. Among the initiatives that could be quantified in this category is the e-Bill initiative which has converted close to 600,000 customers to e-billing. The savings in 2014 capture the reduced postage costs from incremental e-billed customers that were added as a result of active conversion strategies as well as an

improved web interface which has facilitated the sign-up process. Savings of $0.7 million were realized through such initiatives.

44. In addition to the optimization of labour and the processes employed by labour resources, other inputs in the form of materials, equipment, and space were rationalized to achieve greater efficiency. These initiatives involved facilities optimization, the efficient use of printing materials and equipment, the development of in-house capabilities to replace materials outsourcing costs, and the optimal use of fleet equipment to reduce rental costs. This group of initiatives achieved estimated savings of $1.0 million.

45. In the area of policy changes or improvements, the Company sought to reallocate and prioritize program spending through more cost-effective means while ensuring customer safety. These actions either leveraged existing labour capacity to carry out additional tasks or changed the manner in which services were contracted or delivered. For example, a change was made to the Company's Carbon Monoxide ("CO") Alarm Response Policy. Prior to the change, Enbridge responded to all CO alarm calls more often than not duplicating the efforts of the fire department and other first responders. Consistent with gas industry practice, the Company modified its policy such that it now responds to CO calls only when assistance is requested by the first responder who attends to the call. This ensures that customer safety is maintained through appropriate first responder actions; it removes unnecessary duplication and results in lower response costs for the Company. Savings in this category of initiatives amounted to $1.2 million. Because of the lead times needed to achieve some of the changes, savings were partially effective in 2014 and are expected to be higher in 2015.

46. Incremental O&M savings from sustainable productivity actions in 2014 were estimated at $3.5 million.

Table 6:

2014 Incremental Productivity Initiatives		
	O&M Savings ($M)	
Labour Optimization	$	(0.6)
Process Optimization	$	(0.7)
Materials/Space Rationalization	$	(1.0)
Policy Change and Improvements	$	(1.2)
Total Savings from Incremental Initiatives	$	(3.5)

47. In addition to these O&M productivity initiatives, there were others initiatives to find capital spending productivity savings that were previously described in testimony as part of the EB-2012-0459 proceeding which continue to be good examples of productivity improvements. The benefits, however, are or will be difficult to quantify as they span a number of areas and require comparisons to baseline procedures. These initiatives relate to the use of Global Positioning System (“GPS”) Technology, Station Upgrades, and the Work Asset Management Solution (“WAMS”).

48. Capital investments in GPS have created efficiencies for Performance Standard inspectors (“PSIs”), Records Coordinators, and Leak Surveyors who now can create as-laid drawings more precisely and in less time than previously required, and retrieve the most current and relevant information pertinent to their tasks. In addition, GPS location data for mains and valves have been loaded onto navigation devices in field vehicles, providing access to accurate valve locations for inspection or emergency response. The availability of GPS location data in the system

significantly reduces the cost to recreate location records for assets should surrounding areas change over time.

49. Engineering, Operations, Integrity, Corrosion, Environment, Health & Safety departments in Enbridge have been working closely to develop a multi-year workplan for all gate, feeder, and larger district stations. The goal is to track all known station work that is forecast and to coordinate schedules. This coordination is expected to reduce mobilization and demobilization costs, costs associated with programming and re-programing equipment, Hydrovac costs, and inspection costs. Added benefits include station design improvements and better records tracking.

50. The WAMS project replaces existing obsolete technology that supports approximately one million work requests annually and stores asset records associated with providing service to over two million customers. The completed Design Phase of the project has identified opportunities to streamline processes and reduce duplication of tools. It will provide efficiencies for contractor billing and payments, asset design and creation, scheduling, program work, maintenance and inspection.

<u>Variable Costs (Capital)</u>

51. Within the capital budgets filed in the Custom IR proceeding, the Company excluded capital costs which it characterized as “variable” on the basis of their being subject to future developments that would only manifest with information not otherwise known at the time capital budgets were put together. The excluded capital costs are pre-emptive savings that are considered within the total capital budget approved. Productivity efficiencies are achieved only if costs that materialize were absorbed within the capital budget approved. Table 7 below sets out the 2014 variable costs that were identified.

Table 7:

Variable Costs Excluded from Capital Budget ($M)	2014
Sombra Redundancy	2.00
MOP VERIFICATION	5.30
ILI AND ASSESSMENT PRGM	6.20
SVC REPL LT $2M	2.25
COMM IND LOW PRESSURE REG STN	1.53
Load Research Prgm	0.55
STORAGE OVERVIEW	0.28
MCC#1 Generator and Boiler	0.50
meter boxes	0.18
Misc Structures	0.05
Engine Compressor Analyzer Automatio	0.05
Misc. Wells	0.05
Misc Field Lines	0.05
Misc. Meas and Reg	0.05
Roads	0.05
Crowland Plant Automation	0.02
SCADA Upgrade and Automation	0.02
BUS DEV & CUST STRATEGY	2.61
IT PROJ LT $2M	0.90
FAC/GENL PL OVERVIEW	2.50
	25.14

52. Most of the variable capital costs identified for 2014 in the Custom IR filing have been determined to not have materialized. Because of the uncertain nature of these variable cost elements, a number of projects were not adequately itemized or tracked and subsequent changes in scope made it challenging to determine how work items were ultimately captured in the budget or in actual spend. Those variable costs that did arise were mitigated or absorbed within the overall capital spending.

Summary and Sustainability of Savings:

53. Through pooled efforts at all levels of the organization, the Company came close to achieving its embedded savings target of $50.3 million in 2014 through the combination of savings in embedded areas of productivity, incremental productivity

initiatives, and effective capital management. Table 8 provides a breakdown of the 2014 reductions achieved within the areas identified for productivity enhancement.

Table 8:

2014 Productivity-Related Savings						
O&M and Capital						
	O&M ($M)		Capital ($M)		Total ($M)	
	Embedded	Estimated	Embedded	Estimated	Embedded	Estimated
Embedded Productivity Savings	(24.1)	(16.2)	(26.2)	(0.2)	(50.3)	(16.4)
Capital Reductions				(28.7)		(28.7)
Incremental Productivity Initiatives		(3.5)				(3.5)
2014 Total Savings	(24.1)	(19.7)	(26.2)	(28.9)	(50.3)	(48.6)

54. Although $48.6 million was attained in 2014, this specific level will not be sustained. Initiatives within the Embedded Savings and Incremental Initiatives are expected to persist beyond the first year. For many initiatives implemented in 2014, fully-effective savings are expected to manifest in 2015 in addition to enhancements or adjustments that could occur. In addition, following this initial year of reporting, it is expected that tracking and reporting tools and processes would have benefitted from the learnings of 2014 so as to enable refinements with each subsequent year. Finally, through consistent messaging and continued focus within the organization, it is anticipated that the self-reporting of productivity efforts will be heightened as employees and management drive to measurable results.

55. At the same time, capital savings are expected to fluctuate each year in response to the given portfolio of capital projects and the associated priorities that surface as new information is integrated and considered. It is the capital component of savings that does not support the expectation of sustainability as it is highly dependent on the mix of projects and the dynamics associated within each.

56. To ensure continued success, the Company will need to pursue deeper savings to augment those achieved thus far. The Company is acutely aware of the progressively challenging financial hurdles which will make for stringent operating conditions each year of the IR term, requiring it to build savings early on. To that end, it remains committed to delivering operational requirements and commitments at costs lower than approved to optimize ratepayer and shareholder value.

Performance Measures (metrics)

57. Table 9 and Table 10 compare 2014 operational metrics and customer service quality indicators (Exhibit D, Tab 5, Schedule 1) against 2013 results to assess Enbridge's performance in light of the cost reductions achieved. Except in a couple of areas where weather and gas prices negatively impacted the Company's ability to maintain 2013 levels, productivity efforts have not compromised Enbridge's service levels. As seen in the trending columns, Enbridge's performance metrics show that it continues to offer safe and reliable service while improving its value offering to customers.

Table 9:

Operational Performance	**2013**	**2014**	**Trending**
1. Employee Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	+
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	+
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.06	+
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	+
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	+

Table 10:

Customer Relationship Performance	**2013**	**2014**	**Trending**
1. Overall Customer Satisfaction Index	78.0%	77.0%	−
2. Call Answering Service Level (SQR)	75.9%	79.0%	+
3. Percentage of Emergency Calls Responded to within One Hour (SQR)	96.1%	96.9%	+
4. Appointments Met within the Designated Time Period (SQR)	94.2%	95.1%	+
5. Time to Reschedule a Missed Appointments (SQR)	95.0%	95.5%	+
6. Number of Days to Reconnect a Customer (SQR)	92.6%	94.0%	+
7. Number of Calls Abandon Rate (SQR)	2.80%	1.90%	+
8. Meter Reading Performance (SQR)	0.50%	0.69%	−
9. Number of Days to provide a Written Response (SQR)	94.5%	93.3%	−

Witnesses: I. Macpherson
M. Suarez

2015 Custom IR Stakeholder Day

Moderated by:
Andrew Mandyam
Kevin Culbert

What is Stakeholder Day

– Sharing of historical information:
  - Prior year financial and operational performance
  - Provide updates on:
    - Capital Program: Core Capital, WAMS and GTA special projects
    - Asset Management planning
    - Benchmarking in advance of next rebasing application
    - Productivity efforts

– Provide a look at upcoming activities
  - Company strategies and future regulatory activities
  - Gas Supply Planning

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Presenter	Topic	Time (incl questions)
Andrew Mandyam and Kevin Culbert	Company overview	9:00 - 9:20
Ryan Small	Year End Financials	9:20 - 9:40
Scott Dodd and Owen Schneider	GTA	9:40 - 10:00
Will Akkermans and Biju Misra	WAMS & IT	10:00 - 10:20
	Break	
Trevor MacLean	Asset Management	10:35 - 10:55
Hillary Thompson and Ian Taylor	Reinforcements and Relocations	10:55 - 11:05
Brian Black	Storage	11:05 - 11:20
Steve McGill	Community Expansion	11:20 - 11:40
Frank Smith and Paul Green	Customer Growth	11:40 - 12:00
	Lunch	
Ian Macpherson and Margarita Suarez	Productivity and Benchmarking	1:00 - 1:45
	Break	
Andrew Welburn and Don Small	Gas Supply	2:00 - 2:55
Andrew Mandyam and Kevin Culbert	Closing Remarks	2:55 - 3:00

Company Overview

Andrew Mandyam
Kevin Culbert

Enbridge’s Five Areas of Focus

Last year and going forward

– Challenging Year

– Over 500 days without a Loss Time Incident (Safety Success!)
  - Coldest winter in 37 years: Gas Supply management and Operations during coldest and much longer winter in 2014
  - Getting “Out to Construction”: Season commenced later in 2014
  - Customized IR Application and Decision
    - Uncertainty until July, 2014
    - Implementation in last half of 2014

– Near Term Focus
  - Focus on meeting Board Objectives for Ontario Utilities: Customer focus and outcomes based regulation
  - WAMS and Productivity Culture initiative

– Customized IR is an opportunity
  - Sharing information: Prior year and future strategies
  - Understanding Enbridge: Productivity, GTA, WAMS, Asset Management and Capital Management

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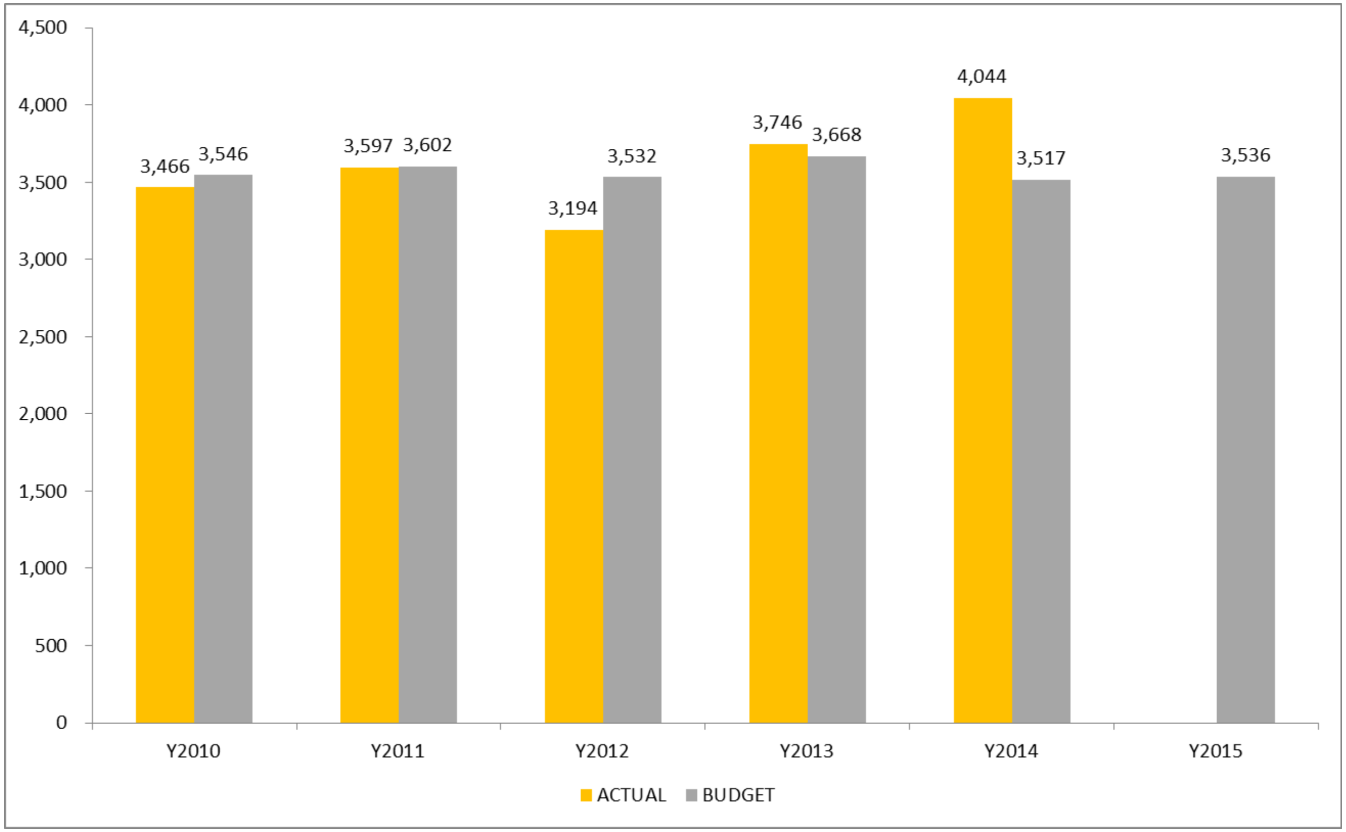
2014 Challenging Year: Heating Degree Days

2010 to 2014: Actual vs Budget



Enbridge is at risk for volumes. 2014 was a year that did not follow the trend.

2014 What we did

- 34,504 Customers Attached

- 2,063,836 average number of unlocked customers (EGD)
- 2,083,513 number of active customers at year end (EGD)

- Over 300 Km of Main related work (installation, replacement, reinforcement etc.)

- GTA and WAMS project commenced

- Volumes throughput 2012-2014:

(Volumes in 10^6m^3)	2012 Actual Normalized	2012 Actual	2013 Actual Normalized	2013 Actual	2014 Actual Normalized	2014 Actual
Total Volumes, Gas Sales and Transportation	11 331.7	10 499.3	11 491.2	11 558.0	11 297.8	12 657.6

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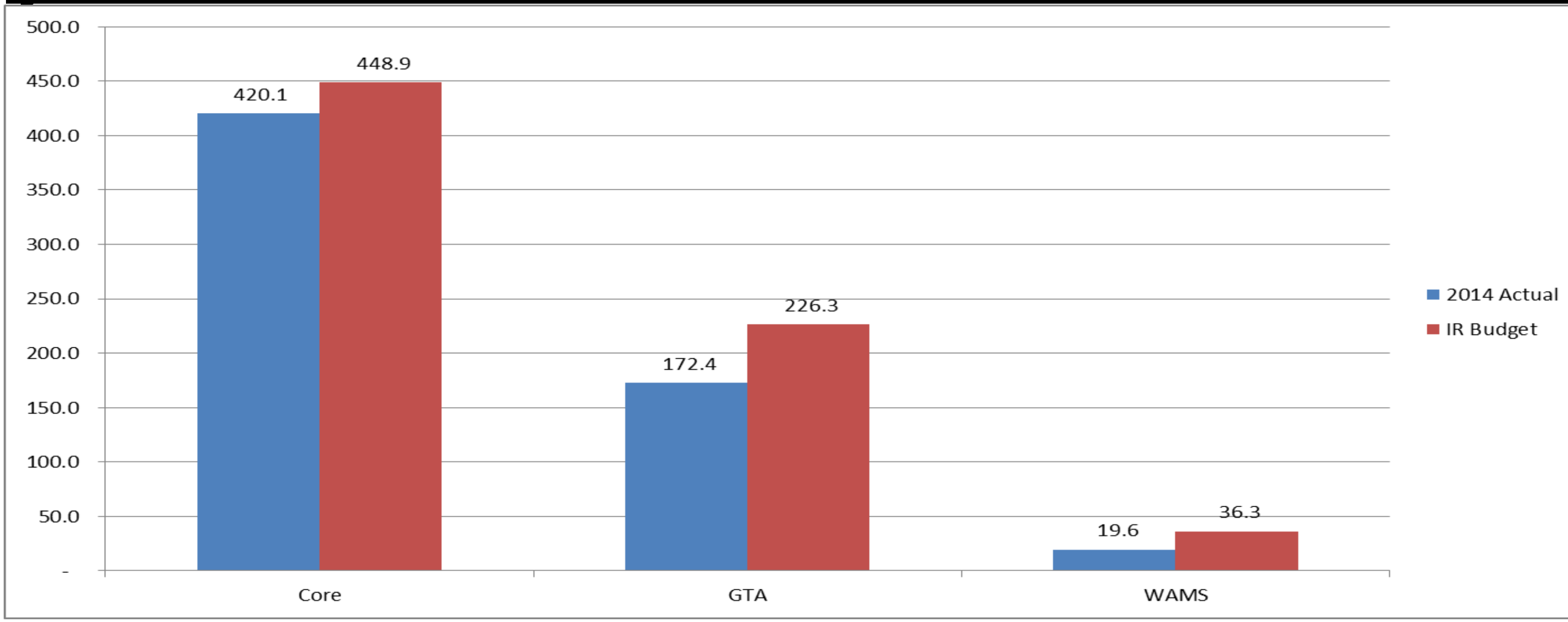
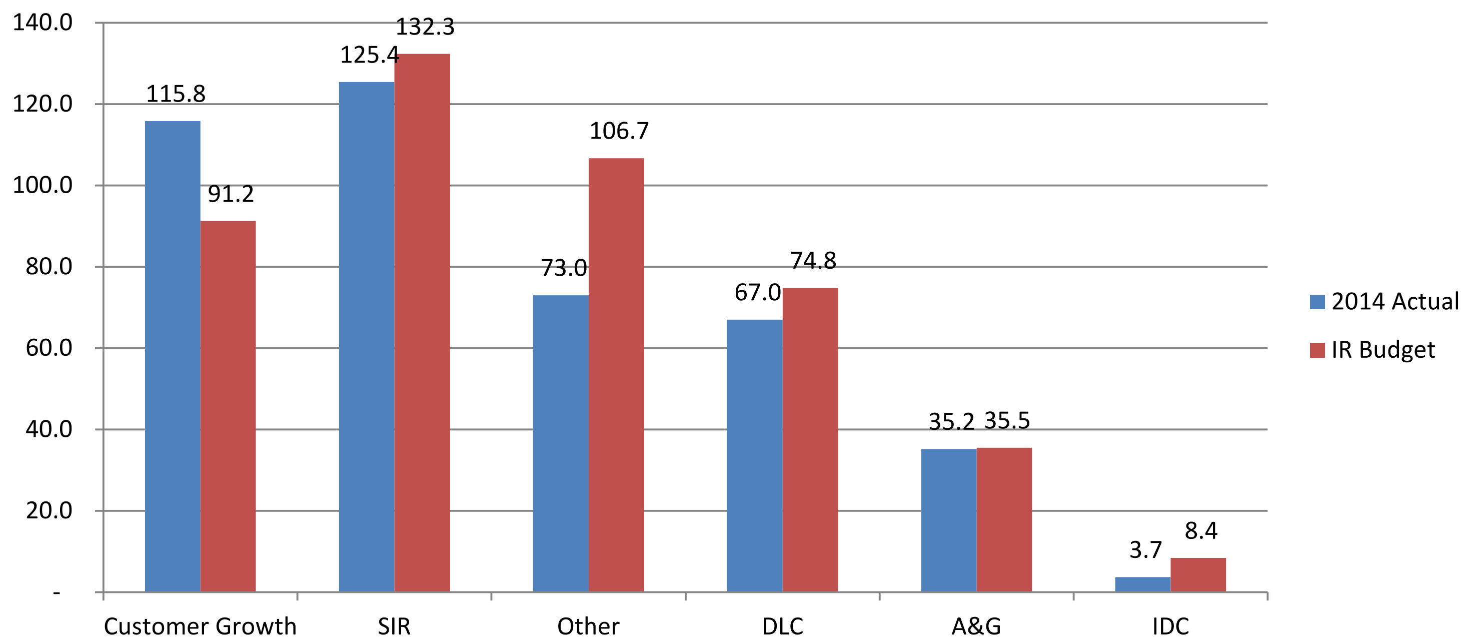
2014 What we did: Capital Management

[redacted]



- $70 M of $99 M Total CAPEX under spend is timing: Spend will occur in a future period
  - GTA ($54M)
  - WAMS ($16M)

2014 What we did: Capital Management



Total Core CAPEX – Major Drivers

- Customer Growth $24 M: Higher cost per customer for "scattered service attachments"
- Labour & IDC of ($12.5 M)
- Reinforcements and Relocations ($14 M): Network analysis outcomes and higher cost recoveries than budgeted
- Storage ($8M): Timing of work
- IT ($9M): System project delivery constraints

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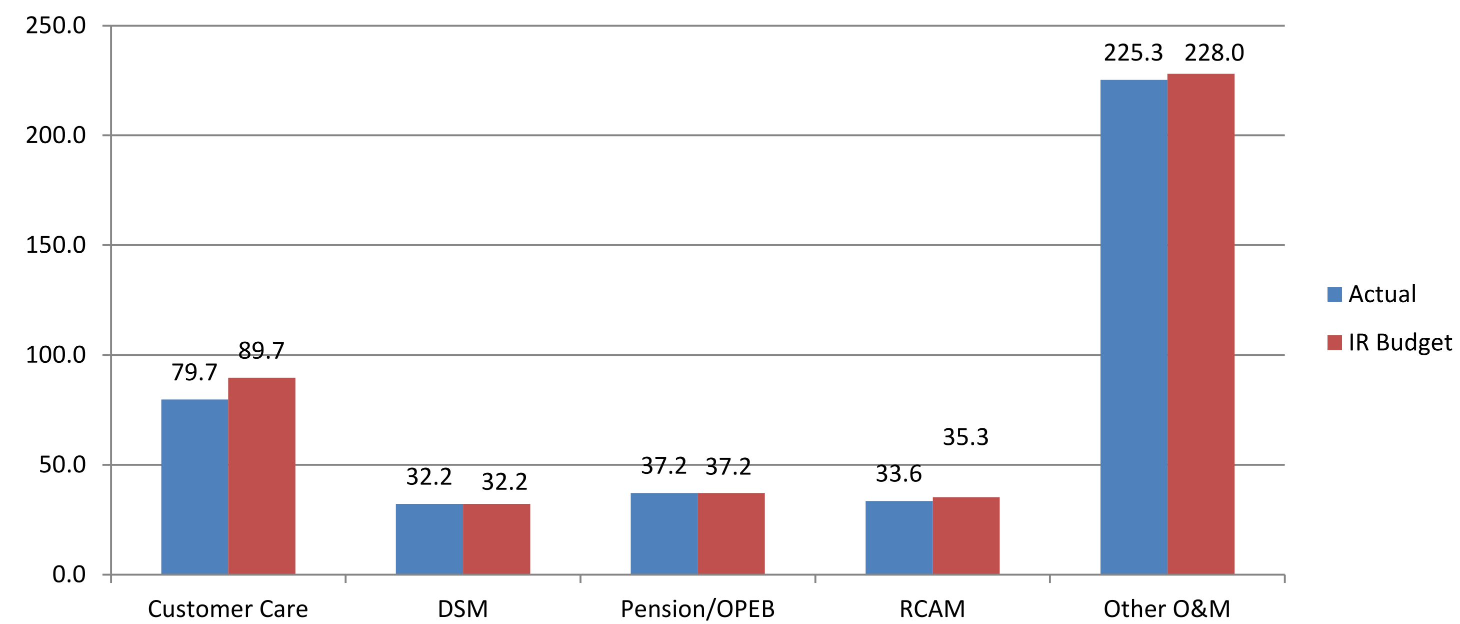
2014 What we did: Operating and Maintenance



Major Drivers:

- Customer Care ($10M) due to Ebill, Collections Process, CIS Support costs, and system improvements to reduce manual work
- RCAM ($1.7M)
- Other O&M ($2.7M)

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2014 What we did : Productivity Culture @ Enbridge

– Executive and Company Priority

- Intake and idea governance: Company leadership group
- Operate the business with starting year's FTE
  - ✓Looking for productivity opportunities that can maintain or reduce FTE levels
- Focus on business outcomes: Customer, Safety, Efficiency, Delivery

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2015 Regulatory Activity

- 2015 Rates Application Update: Partial settlement
- Dawn Access Settlement: Phase 2 consultation
- DSM: multi year plan proposal will be filed today
- 2014 ESM & Deferral / Variance account application – April 2015
- 2015 CIR Rate Application - September 2015
- Benchmarking report: will be reviewed in Productivity presentation that follows
- Asset Management plan: will be reviewed in Asset Management presentation
- Service Quality Reporting: results will be filed within the 2014 ESM application
- Nexus: Contract pre-approval
- Storage and Transportation Access Rule – requirement for GTA Segment A transmission

Year-end Financials

Ryan Small

2014 Utility Return on Equity – Actual vs. Approved

– 2014 Gross Revenue Sufficiency = $25.3M

– 2014 ESM = $12.65M

– 2014 Actual Normalized ROE Before ESM = 10.46%

– 2014 Actual Normalized ROE After ESM = 9.91%

– 2014 Board Approved ROE = 9.36%

2014 Utility Rate Base – Actual vs. Approved

Line No.		Actual (Incl. CIS) ($Millions)	EB-2012-0459 Approved (Incl. CIS) ($Millions)	Variance ($Millions)
1.	Net property, plant, & equip.	4,315.8	4,163.0	152.8
2.	Gas in storage	402.7	279.9	122.8
3.	Other working capital items	(17.2)	(21.5)	4.3
4.	Utility Rate Base	4,701.3	4,421.4	279.9

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2014 Utility Capital Structure – Actual vs. Approved

2014 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	2,705.7	57.55	5.41	3.113	146.4
2.	Short term debt	203.1	4.32	1.38	0.060	2.8
3.	Preference shares	100.0	2.13	2.40	0.051	2.4
4.	Common equity	1,692.5	36.00	9.36	3.370	158.4
5.		4,701.3	100.00		6.594	310.0

EB-2012-0459 2014 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	2,633.9	59.57	5.57	3.316	146.6
2.	Short term debt	95.8	2.17	1.78	0.039	1.7
3.	Preference shares	100.0	2.26	2.96	0.067	3.0
4.	Common equity	1,591.7	36.00	9.35	3.365	148.8
5.		4,421.4	100.00		6.787	300.0

* Lower LTD rates acquired will be reflected and provide a benefit within 2015 through 2018 rates.

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2014 Utility Income – Actual vs. Approved

Line No.		Actual (Incl. CIS) ($Millions)	EB-2012-0459 Approved (Incl. CIS) ($Millions)	Variance ($Millions)
1.	Distribution margin	997.5	980.2	17.3
2.	Other revenues	43.9	42.8	1.1
3.		1,041.4	1,023.0	18.4
4.	O&M (incl. CC/CIS rate smoothing adj.)	408.0	422.4	(14.4)
5.	Depreciation and amortization expense	255.9	248.5	7.4
6.	Fixed financing costs	2.3	1.9	0.4
7.	Municipal and other taxes	40.5	41.2	(0.7)
8.	Total costs and expenses	706.7	714.0	(7.3)
9.	Utility income before income taxes	334.7	309.0	25.7
10.	Income tax expense	6.1	8.9	(2.8)
11.	Utility net income	328.6	300.1	28.5

2014 Allowed Revenue & Sufficiency – Actual vs. Approved

Line No.		Actual (Incl. CIS) ($Millions)	EB-2012-0459 Approved (Incl. CIS) ($Millions)	Variance
1.	Cost of capital	310.0	300.0	10.0
2.	Cost of service (incl. CC/CIS rate smoothing adj.)	2,351.6	2,170.3	181.3
3.	Other misc. operating and non-operating revenue	(43.9)	(42.8)	(1.1)
4.	Income taxes on earnings	6.1	8.9	(2.8)
5.	Taxes on sufficiency	(6.7)	-	(6.7)
6.	Allowed revenue	2,617.1	2,436.4	180.7
7.	Revenue at existing rates	2,642.4	2,436.4	206.0
8.	Gross revenue sufficiency	25.3	-	25.3

* 2014 earnings sharing payable to ratepayers = $12.65M

GTA

Scott Dodd
Owen Schneider

GTA Project Introduction

- The Company has not had a major infrastructure reinforcement since 1992.
- Since that time, Toronto and the GTA has experienced substantial growth.
- The GTA Project provides solutions:
  - Customer growth
  - Reduces gas supply costs
  - Reduces operational risks and enhances safety
  - Provides system diversity
  - Improves gas supply chain diversity and reduces upstream gas supply risk

https://www.youtube.com/watch?v=Oyptu8sCe2g

GTA Project Map

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GTA Project Scope

Segment A

- Shared Regional Transmission / Distribution Pipeline
  - 27.4 km NPS 42” Pipeline from Parkway to Albion
  - Provides 1,200,000 GJ/d capacity to TransCanada Pipelines to supply their King’s North Project, which allows for increased transmission capacity for the GTA and Eastern Canada. Recovery in Rate 332
  - 800,000 GJ/d of new distribution capacity for growth, diversity, safety, and supply benefits

Segment B

- Distribution Pipeline
  - 23.0 km NPS 36” Pipeline from Keele to Sheppard
  - Provides reinforcement for growth, safety, and supply benefits

Facilities

- Parkway West Gate Station
- Parkway Cons Bypass Station
- Albion Road Station
- Keele / CNR Station
- Jonesville Station

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Construction Photos - Beaver Creek HDD Start

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Construction Photos – Beaver Creek HDD Pipe Pullback




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Credit River – Direct Pipe Micro Tunneling

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Credit River – Direct Pipe Micro Tunneling

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Credit River – Direct Pipe Micro Tunneling

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Drivers of 2014 Actuals ($MM)

	2014	Project
2014 EB-2012-0459 Approved	226.3	686.5
2014 Actuals	172.4	
Variance to EB-2012-0459 Approved	(53.9)	

- Overall lower 2014 costs than projected due to timing differences.
- Main Trends
  - Lower costs for land/land rights and facilities
  - Slightly higher costs for pipeline related expenses
- Key Drivers
  - Start of all major construction activities in 2015
  - NPS 42 mainline pipe delivery in 2015
  - Lower land/land rights, labour, project overheads, IDC

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2015 Considerations

- 2015 is the key construction and spend year
  - All facilities, HDDs, and mainline work will occur in 2015
  - Higher contracted prices for both facilities and mainline contractors have driven the 2015 forecast
    - 2014 Market Conditions experienced during competitive RFP process
    - Difficulty of the work areas in GTA
  - Key challenge is permits

- Total forecast project cost of $756 MM
  - Versus approved $687 MM is $69 MM (10%) higher than 2014 Decision with Reasons*

- In Service Date is forecast for Q4 2015
  - Residual restoration and closeout costs in 2016

*EB-2012-0459

WAMS

Will Akkermans
Biju Misra

Background

– Work and Asset Management Solution (WAMS) will be a fundamental business tool and is foundational to providing safe and reliable service to our utility customers.

– WAMS will replace existing obsolete technology that supports approximately one million work requests every year and stores asset records associated with servicing over two million customers.

– Over 1,500 people use the related data, processes and technologies.

– Existing Technology is problematic because it is based on an operating system that will no longer be software vendor supported after 2015

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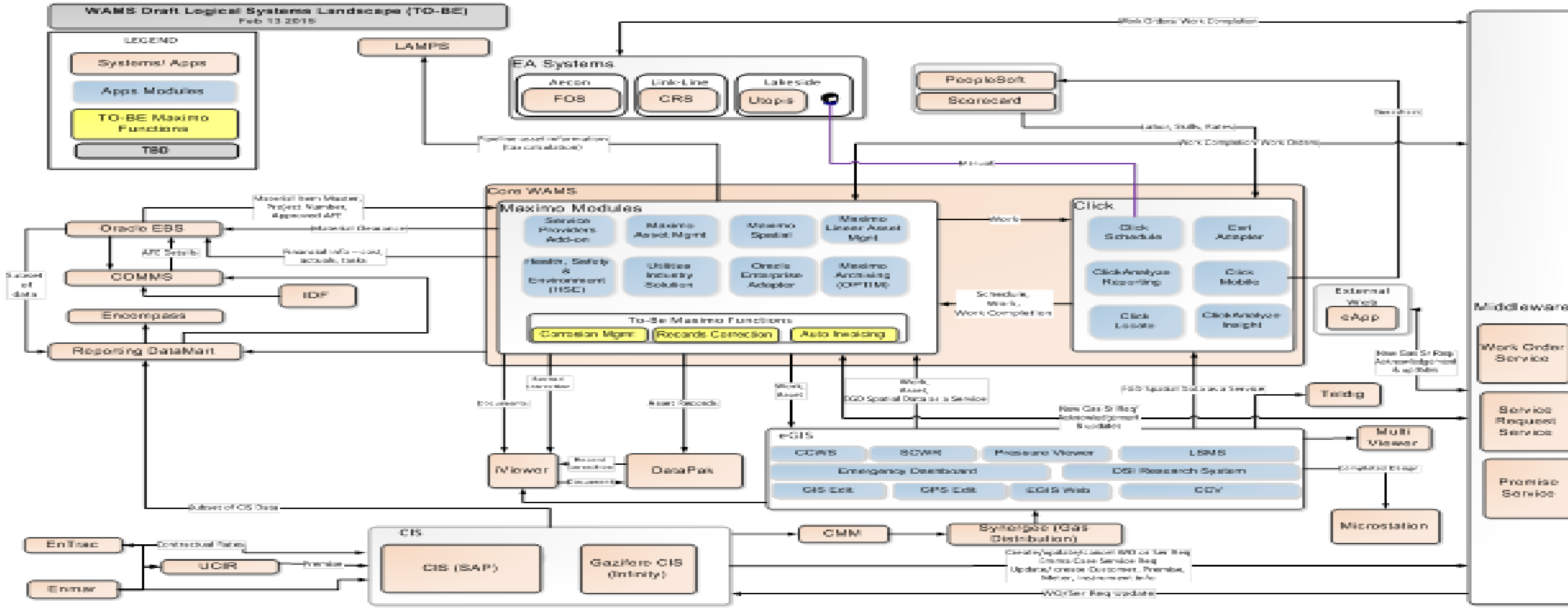
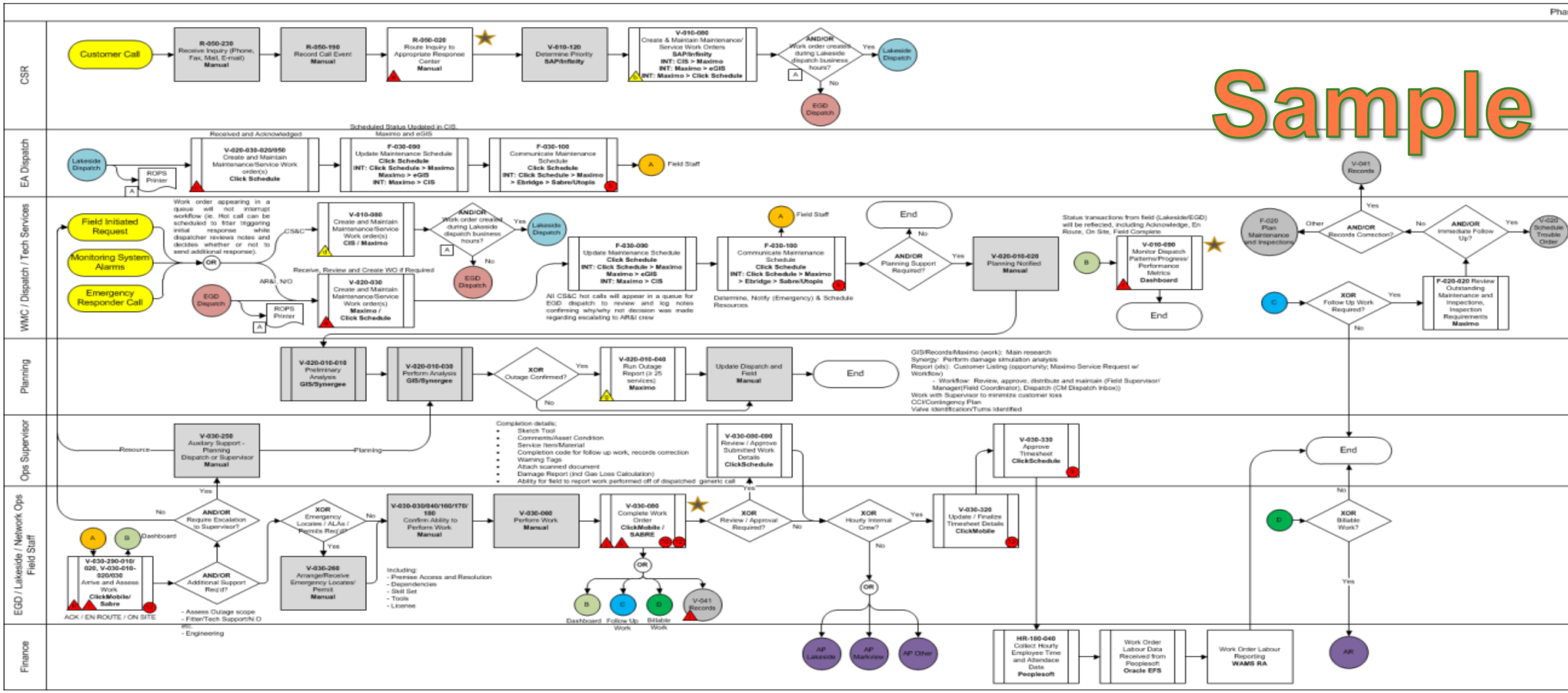
Technology Complexity



- 20+ systems to interface
- Numerous internal & external systems to enhance Work & Asset management discipline within the company
- CIS, GIS, Financials, HRIS as well as downstream systems within our Extended Alliance
- 60+ interfaces to build
- Implementation will eliminate technology risk and provide a platform for the future

Business Complexity



- Over 200 people across the company have been involved in requirement definition / design
- Key business processes have been analyzed, streamlined, and documented
- Over 700 business requirements have been identified as critical for meeting operational commitments and compliance

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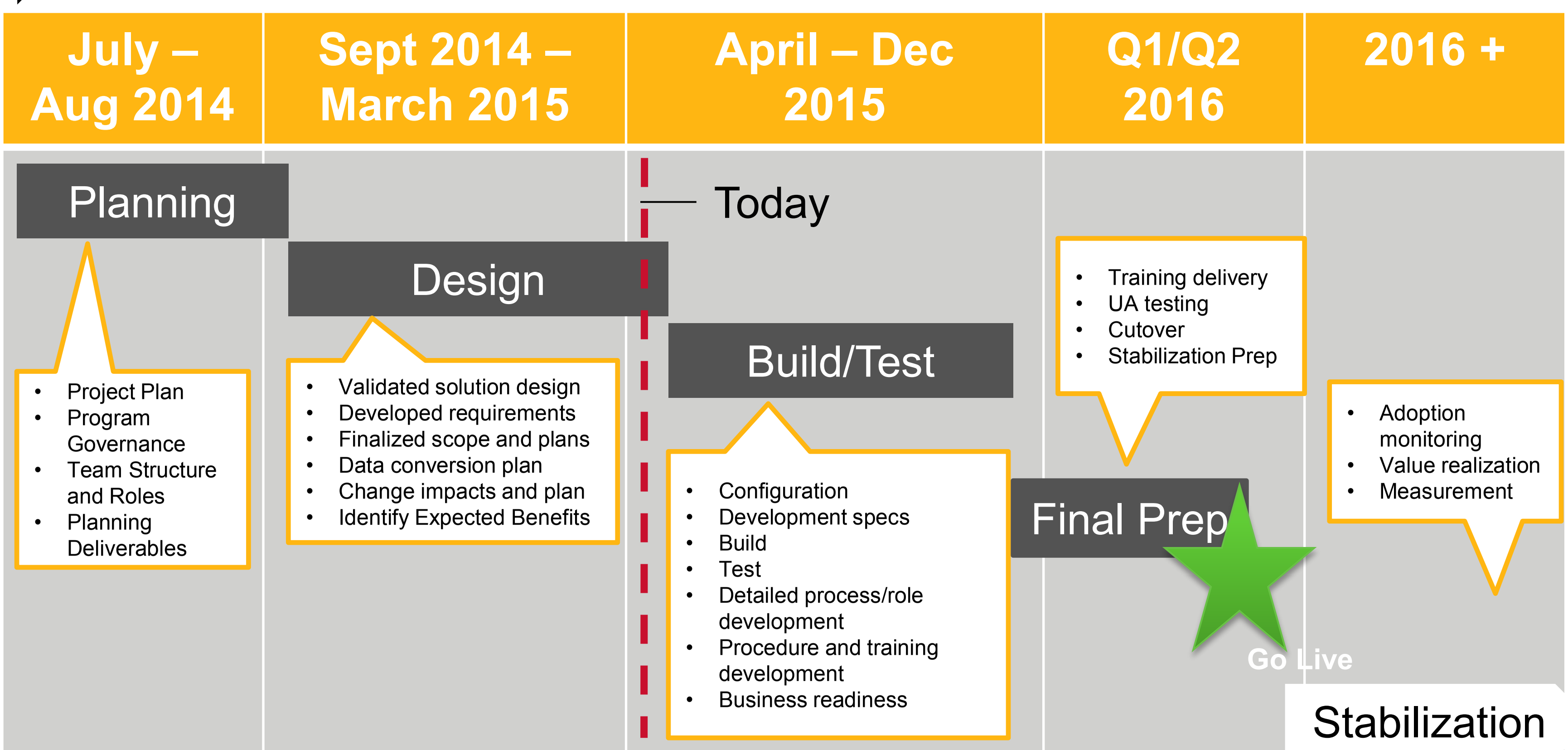
WAMS Implementation Approach



WAMS - 2014 Annual Capex	2014 Budget	2014 Act	Variance
B2-8-2 WAMS	$ 36,349.00	$ 19,605.98	$ 16,743.02

- On-going focus on Risk Management & Quality Assurance in all phases

Expectations post Go-Live

- Primary benefit is to replace Envision as the technology has become obsolete
- Design Phase has identified opportunities across safety, productivity, customer, employee and finance
  - Streamline processes and eliminate spreadsheets and Access databases
  - Contractor Billing and Payments
  - Asset Design and Creation
  - Scheduling
  - Program work, maintenance and inspection

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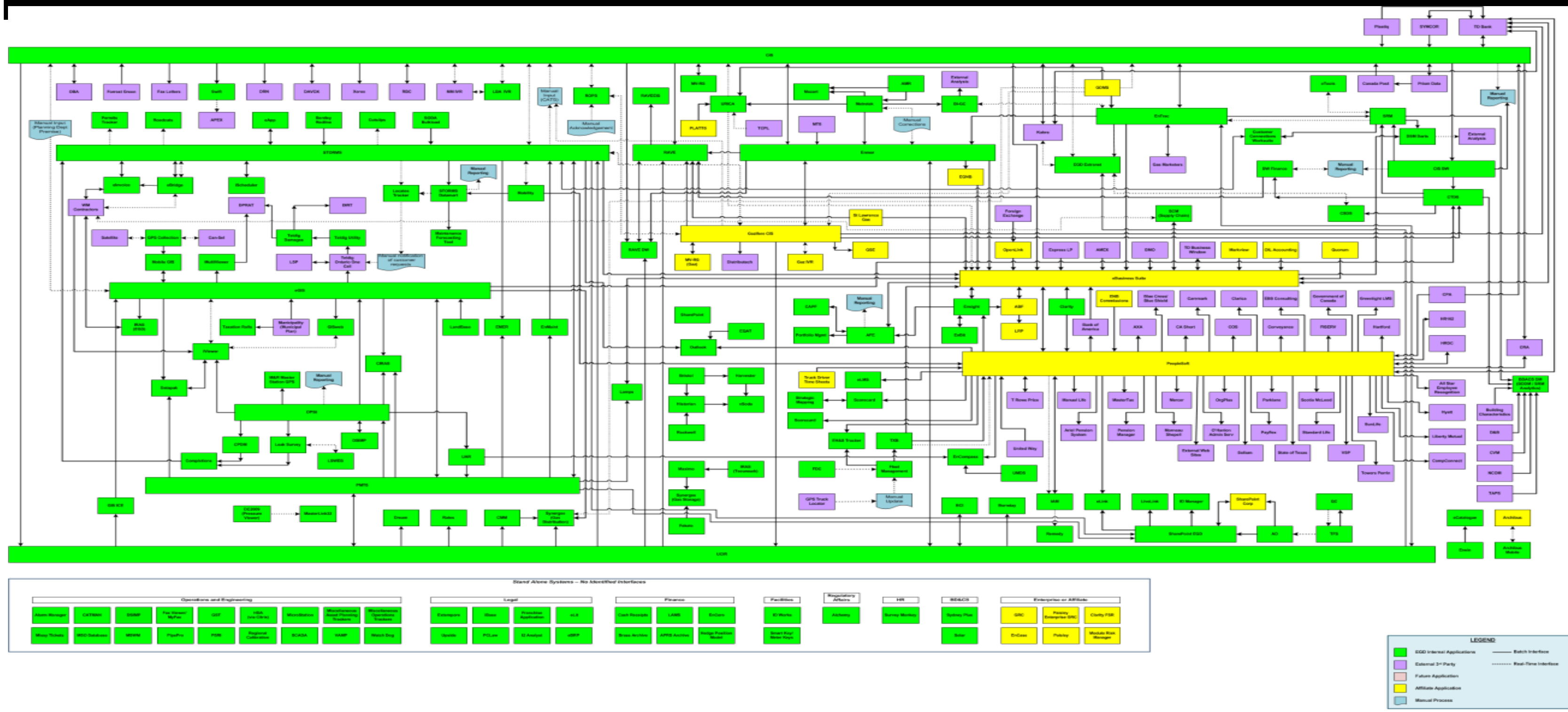
IT

Biju Misra

Background

[redacted]



- Ensuring that all of the Company's systems operate in a secure, reliable, and effective manner
- Delivering Information and Technology projects that meet the Company's evolving business and operational needs
- Supporting all existing software and hardware solutions that enable the Company's day-to-day operations

2014 IT capital spend variance spend under by $9M

Major drivers:

- **Business Applications:**
  - **Delayed CIS SAP Software Upgrade:** Reduction in capital spend of $3.5M. Project was delayed to accommodate the peripheral system upgrades and to stabilize our hardware environment prior to starting the CIS Software Upgrade. The new timing of this spend is 2015 and will be managed as part of 2015 budget.

  - **Reduced scope of CIS Releases:** The reduction of $1.3M was a result of the Bill Redesign and CIS Archiving projects which introduced larger changes than expected and required more resources for design and testing

- **Enhancements Projects:**
  - **Delayed Customer Website Redesign:** Reduction in capital spend of $3.0M. Enbridge undertook a review of the overall Digital Strategy for the company and thus the new customer website design has yet to be developed.

Other:

- Competing priorities with Peripheral System Upgrades and Bill Redesign

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Asset Management

Trevor MacLean

What is Asset Management?

- System which optimally and sustainably manages assets and asset systems
- Where performance, risks, and expenditures over asset life cycles are optimized
- For the purposes of achieving Enbridge's commitment to internal and external stakeholders
- Which is linked to the strategic plan

Board Feedback

Robust asset management planning should:

- Include all the company's assets
- Be based upon a comprehensive process of condition assessment, risk evaluation, and prioritization

The asset plan should:

- Be the vehicle to perform rationalization, prioritization, optimization
- Be directly linked to the budget

We agree!

What are we working on?

- AM system based upon ISO 55000 industry standard
  - Defines scope, regulatory aid, process discipline, galvanize our people
- Roles & accountabilities:
  - New specifically designated asset management roles
- Tool sets:
  - Updated risk assessment methodology/model
  - Investment planning tool that allows project value and risk to be optimized
  - Refreshed centralized risk register & centralized capital project register.
- Processes:
  - Direct link of business cases & risk assessment to capital planning/budgeting
  - Cross functional metrics supporting full lifecycle decision making
  - Fully documented processes that sustain a robust AM system

Specific Progress & Intent

- Dedicated AM project team in place (focus)
- New AM roles in place – (accountability & single plan)
- RFP underway for asset investment planning (AIP) tool (tradeoffs)
- Strengthened risk assessment group & processes (impartial comparability)
- 3 Phase project plan
  - Phase 1 - gas carrying assets, roles, risk improvements, standalone AIP tool - summer/fall 2015
  - Phase 2 - improved processes, better asset analytics, fully implemented AIP tool – mid 2016
  - Phase 3 - all assets, sustaining processes, continuous improvement – mid/late 2017
- 3rd Party Independent Review
  - To be engaged late 2015 for multi-year engagement
  - Report on progress tied to key milestones of the project plan
  - Will compare to best practice/ISO 55000
  - Final report will be filed as part of future rate application

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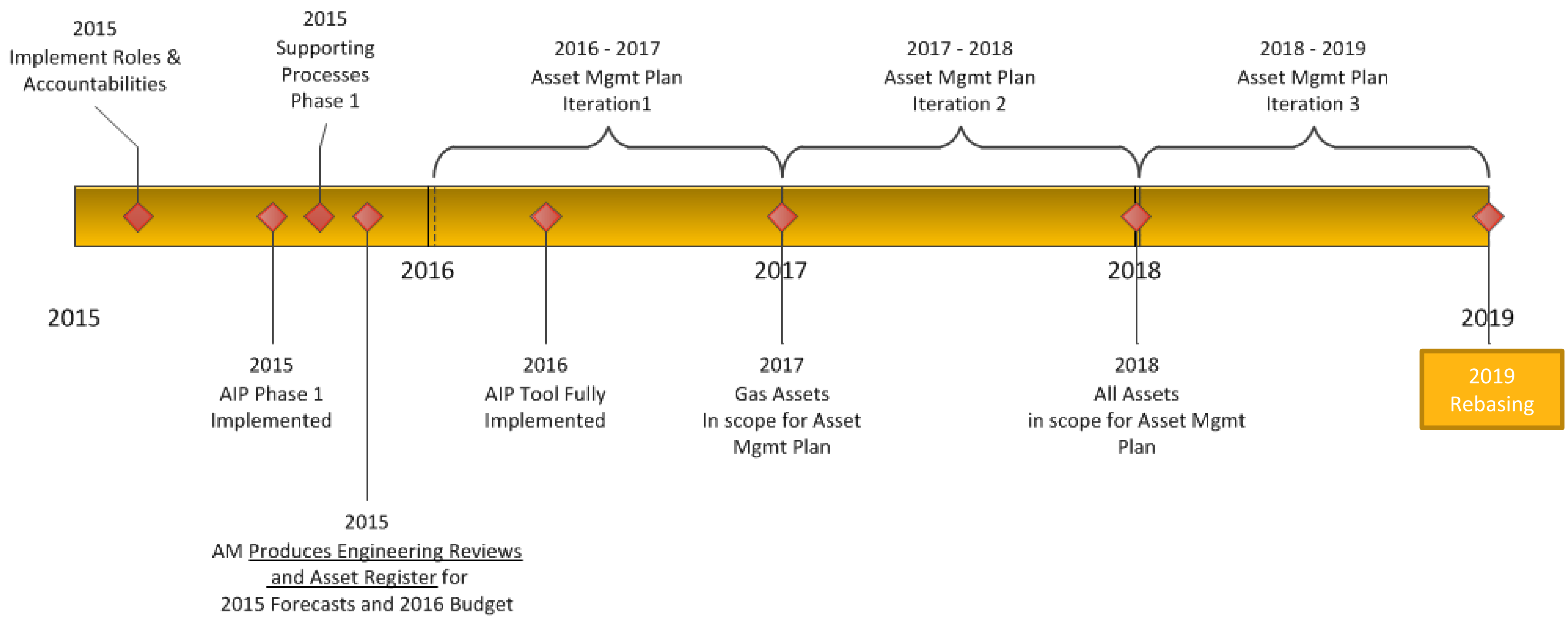
High Level Asset Management Project Timeline

DRAFT



Reinforcements and Relocations

Hillary Thompson
Ian Taylor

Reinforcements

- Reinforcements are planned to meet the anticipated peak hourly demand and are primarily driven by:
  - Customer growth
  - System reliability considerations
- Projects are identified through the completion of four major functions:
  - load gathering
  - Simulation
  - annual forecast
  - long range system planning
- As a result of these functions, the timing of reinforcements are evaluated on an annual basis to trigger work at the right time.

Reinforcements

[redacted]

B2-3-1 Reinforcements	2014 Actuals	2014 IRM Budget	2015 IRM Budget	2016 IRM Budget
Total (‘000)	$3,130	$11,393	$16,958	$8,743

– Major Drivers:

- The timing of reinforcements was evaluated based on the most up-to-date information through the process previously outlined, i.e.:
  - NPS 8 XHP near Peterborough ($1.5M)
  - Pressure elevation, HP to XHP, near Richmond ($1M)
  - NPS 12 IP in Ottawa ($1.2M)
- Project schedules were also impacted by other influences, such as:
  - Land availability (i.e. easements) – NPS 12 HP on Steeles in Markham ($1.5M)
  - Permitting delays (i.e. provincial, regional, municipal, environmental) – NPS 8 XHP on Highway 10 near Dundalk ($1.9M)
  - Changes to municipal schedules (i.e. where reinforcements projects were planned to align with relocations) – NPS 8 IP on Queen St in Brampton ($0.3M)

Relocations

- Capital required to relocate existing plant under franchise agreement and legislation as a result of third party construction projects
- Primarily dependent on external infrastructure spending and timelines
- Cost sharing mechanisms exist to recover some or all of relocation project costs

Eglinton crosstown relocation for Metrolinx

Keele and Finch relocation for TTC

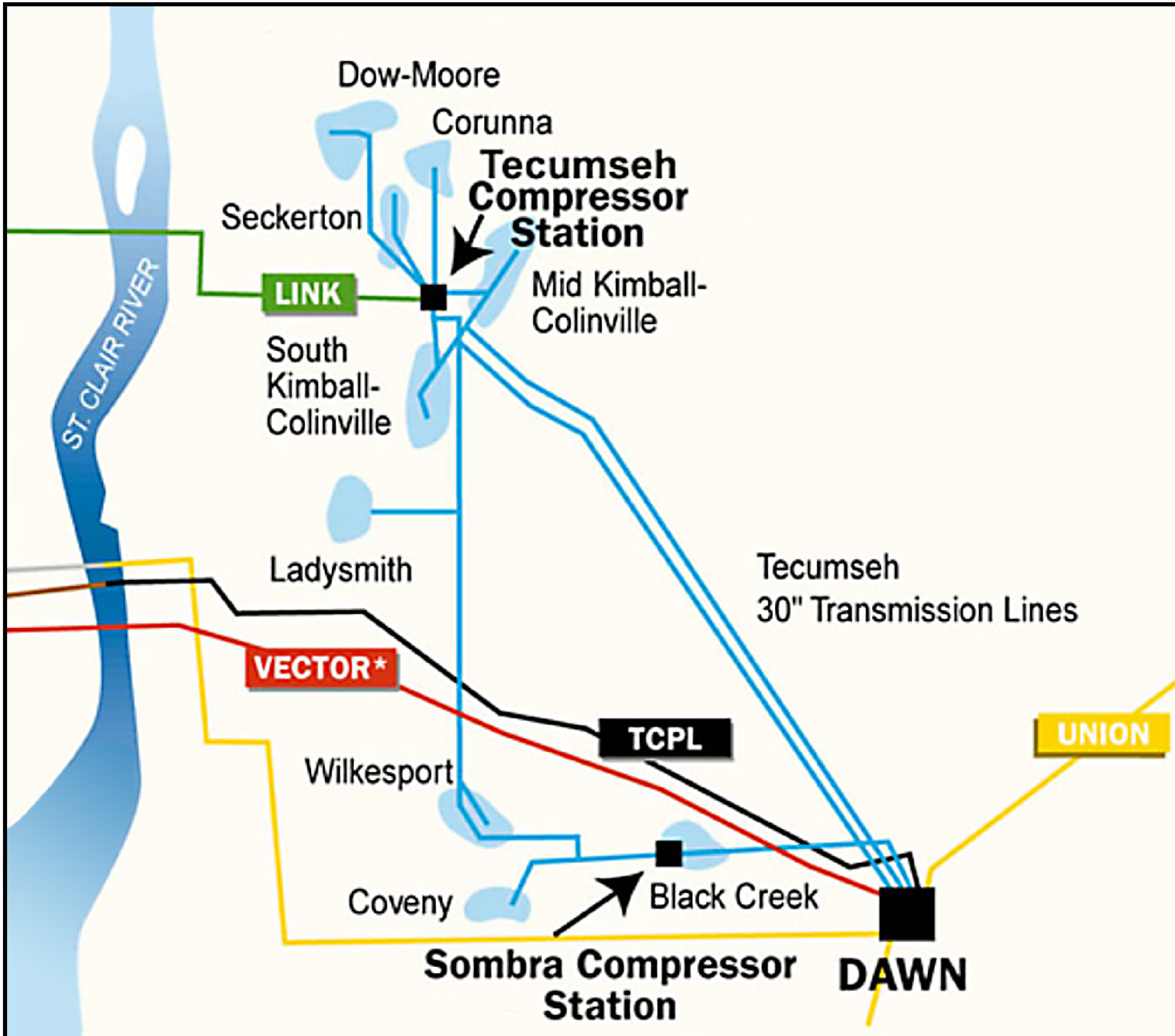
Relocations 2015 and beyond considerations

B2-4-1 Relocations	2014 Actuals	2014 IRM Budget	2015 IRM Budget	2016 IRM Budget
Total (‘000)	$9,350	$15,236	$13,386	$12,603

- Cost sharing mix changed resulting in greater credits than budgeted
- 2015 is currently forecast at $23.4M including $13M for York Region Rapid Transit
- Regional transit work and other large scale infrastructure work continue to be the biggest impact.
  - York Region Rapid Transit (YRRT) costs are shared with the region under franchise agreement.
  - Eglinton Cross Town costs are fully funded by the TTC.

Storage

Brian Black


Dow-Moore
Corunna
Tecumseh Compressor Station
Seckerton
LINK
Mid Kimball-Colinville
South Kimball-Colinville
ST. CLAIR RIVER
Ladysmith
Tecumseh
30" Transmission Lines
VECTOR*
TCPL
UNION
Wilkesport
Black Creek
Coveny
Sombra Compressor Station
DAWN

Gas Storage

One of Eleven Integral Compressor Units at Corunna Compressor Station

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Gas Storage

2014 Actual and IRM Budget from 2014 through 2016 (units $ 000)

	Col. 1 2014 Act	Col. 2 2014 IRM	Col. 1- Col 2. Variance	2015 IRM	2016 IRM
Compressor Programs	1,292	783	509	863	1,025
Observation Wells	841	1,850	(1,009)	2,450	1,600
Tecumseh Compressor Plant	3,084	9,680	(6,596)	4,620	-
Other	6,447	6,855	(408)	5,875	6,285
	11,664	**19,168**	**(7,504)**	**13,808**	**8,910**

- **Compressor Programs** – cold winter & lower injection cycle pressure resulted in more engine hours and overhauls
- **Observation Wells** – deferred the drilling of one of the two planned observation wells
- **Tecumseh Compressor Plant** – commencement of construction of the new office/shop/control room building was deferred from 2013 to September 2014.

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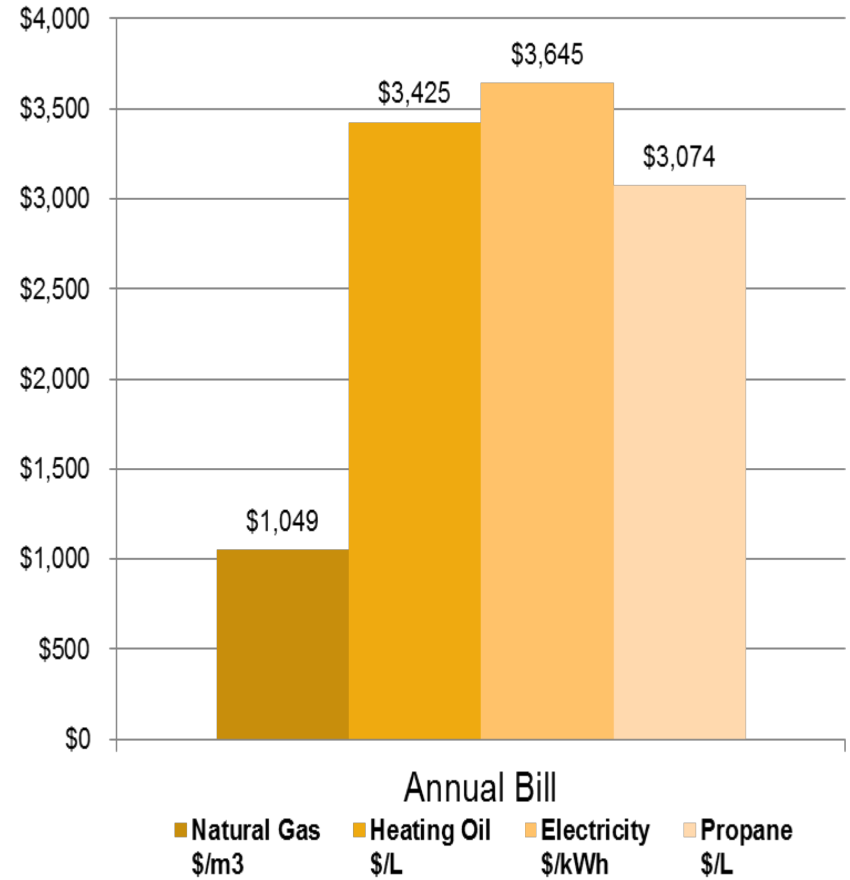
Community Expansion

Steve McGill

Why Community Expansion?

- Demand from communities to extend natural gas system
- Significant changes in energy prices over last five years
  - Potential for natural gas annual savings of $1,300 to $2,300 per customer compared to fuel oil, electricity and propane for home heating / water heating
- End-use economics present unique opportunity where all stakeholders are better off with increased expansion of system
- *Potential to add 10-15 K customers @ $12,000 - $15,000 per addition*
  - *Minimum of $120 MM in capital*
  - *Potentially $180 - $225 MM in capital depending on costs / penetration of communities*
- Provincial Government interest



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Political & Regulatory Environment

- Incentive Regulation (IR) framework in 2014 – 2018
  - The incremental capital investment for a broad community expansion program has not been Included in Enbridge's current IR Model (EB-2012-0459, Exhibit I.B18.EGDI.SEC.84)
    - The revenue requirement associated with the incremental investment for community expansion would not otherwise be reflected in utility rates until they are rebased in the next Cost of Service rebasing, assumed to take place in 2019, therefore the Company will seek a pass through to rates ("Y Factor" treatment) for these investments

- Municipalities are pushing us to extend service to their communities
  - The Company is aware of numerous requests for service from municipalities
  - The Company is also aware of the fact that several Ontario municipalities are about to request expressions of interest from the market in connection with the provision of natural service gas to their communities

Political & Regulatory Environment Continued

- Provincial Government Support
  - The province has announced its commitment to provide up to $200 million in loan funding and an additional $30 million in grant funding to assist the extension of natural gas service to currently un-served communities

- Regulatory Interest
  - February 18, 2015 OEB letter inviting parties to bring forward proposals to extend natural gas services to new communities that;
    - incorporates regulatory flexibility (e.g. ROE, depreciation period, recovery of capital contribution, etc.),
    - fosters predictability and cost certainty from consumer perspective, and
    - minimizes impacts on existing natural gas ratepayers.

Potential Communities

Potential Communities – Central Region

Community	Population	Potential Customers
Fenelon Falls	4600	1800
Bobcaygeon	4400	1700
Kirkfield	2000	800
Scugog Island	1500	600
Enniskillen	500	200
Haydon	300	100
Udora	1000	400
Woodville	800	300
Zephyr	800	300
Leasksdale	500	200
Sandford	500	200
Haliburtion	2000	800
Minden	1300	500
Coboconk	1000	400
Kinmount	500	200
Norland	500	200
Cameron	300	100

Potential Communities – Eastern Region

Community	Population	Potential Customers
Lanark & Balderson	1000	400
Kinburn/Fitzroy Harbour	1300	500
Cambray	1000	400
South Glengary	500	200
Bainsville	300	100
Maxville	1000	400
St. Isidore	1000	400
Chute-a-Blondeau	500	200
Sarsfield	500	200
Westmeath	500	200
Curran	300	100
Eganville	1800	700
Barry's Bay	1300	500
Douglas	500	200
Cotnam Island	300	100

Enbridge Current Thinking

- To bring a community expansion application to the OEB for approval in 2015 under Sections 36 and 90 of the OEB Act
- The application will target several communities (“Phase 1”)
- This application will include a request for a capital pass through to rates (Y Factor Eligibility)
- Potential EBO-188 Guideline relief;
  - Request a reduction in the Project Minimum Profitability Index – e.g. (“PI”) to 0.6 from 0.8,&
  - Request a reduction in the Investment Portfolio Minimum PI – e.g. to 0.9 from 1.0
- The application will seek to establish a Volumetric Rate Rider (“Expansion Surcharge”) to enable the collection of customer contributions in aid of construction with respect to these projects over a number of years

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Enbridge Current Thinking Continued

- The Enbridge proposal will take an integrated approach that combines Regulatory Flexibility, the Community Expansion Surcharge and Provincial Government financial support

Enbridge Current Thinking Continued

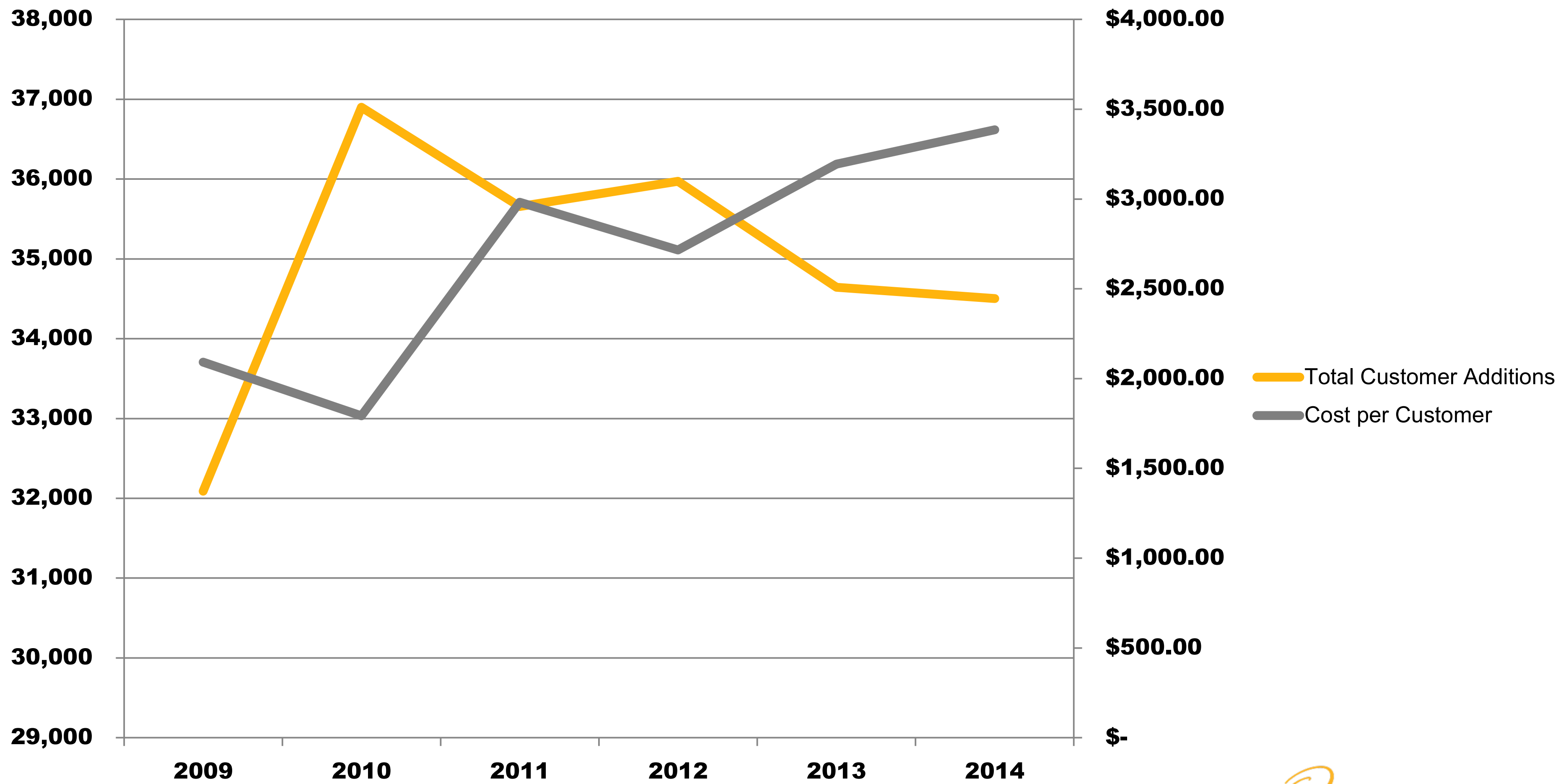
- Increasing responsiveness to customers and reducing regulatory administrative burden is desirable
- Where appropriate, expansion tools decided upon by the OEB would be applicable to additional projects whether or not a leave to construct application is required
- Targeted implementation date would be 2016/2017 heating season for the first tranche of communities

Customer Growth

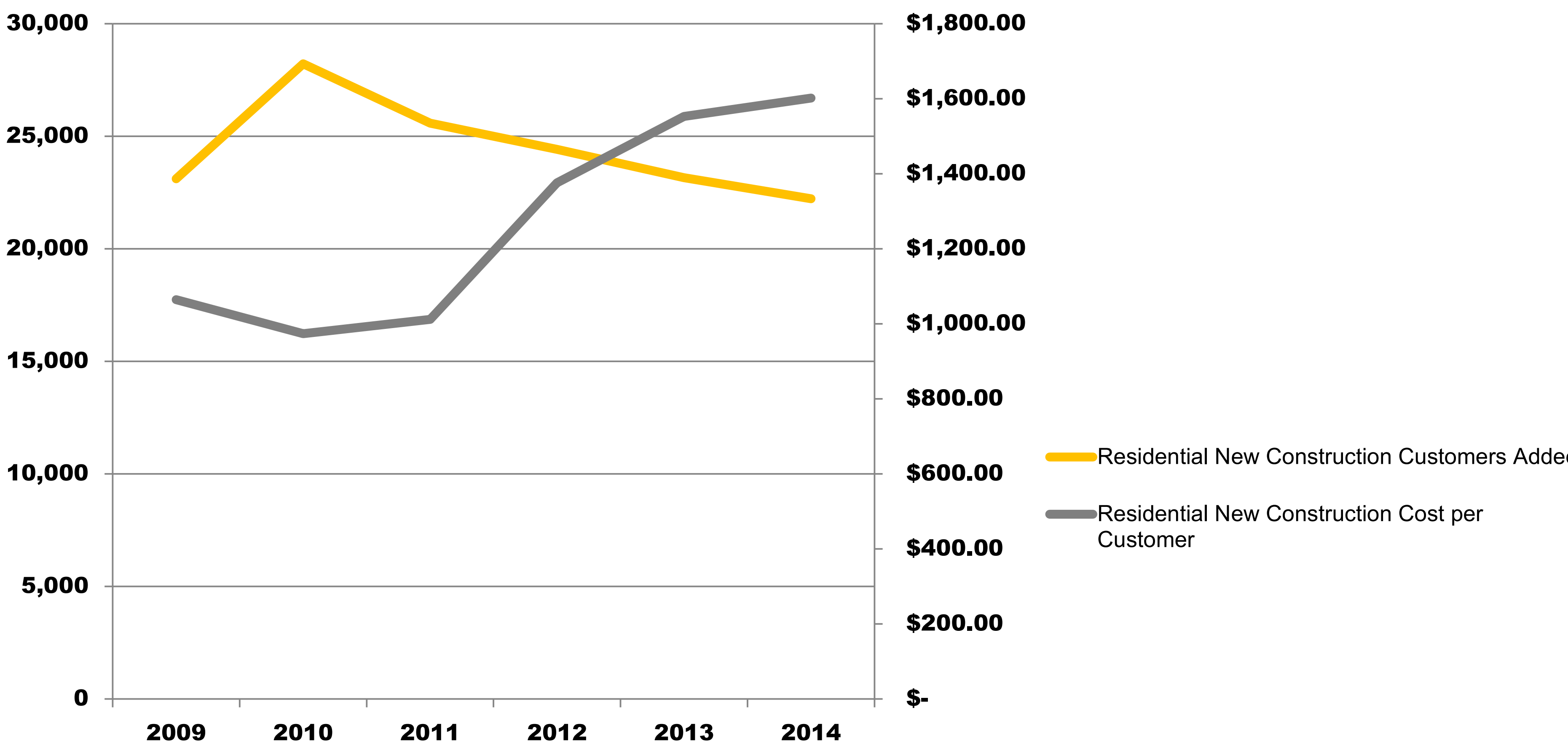
Paul Green
Frank Smith

Total Customer Additions and Cost Per Customer History

[redacted]



Residential New Construction Additions and Cost Per Addition Segment History



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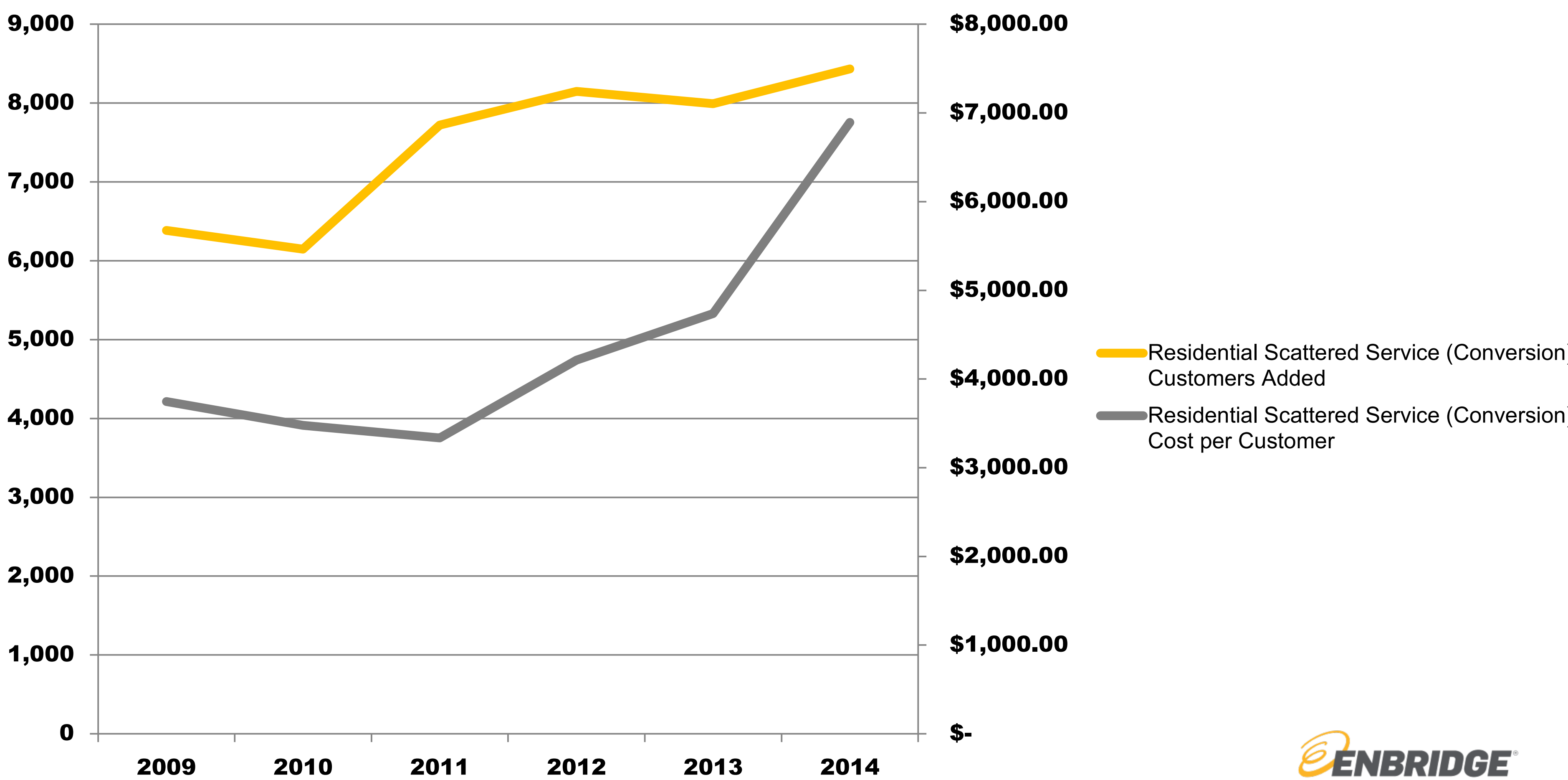
Residential Scattered Service (Conversion) Additions and Cost Per Addition Segment History



Construction Environment

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Challenges and Focus

- **Challenges**
  - Municipal fees per customer have increased
  - Supply and demand pressures in the contractor labour market
  - Full year construction
  - Managing market sectors

- **Focus**
  - Establishment of long-term construction contracts extending beyond the IR term
    - Efficiency clauses embedded within contracts
  - Minimize winter construction work in most market sectors
  - Expansion of Joint Utility Trench as a construction practice across EGD
  - Formation of Joint Utility Trench consortium to create efficiencies across the Joint Utility Trench marketplace

Productivity & Benchmarking

Ian Macpherson

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Enbridge's Commitment

- **Custom IR provides the appropriate regulatory framework given the company's needs; Productivity is an important element of this framework**
- **Productivity savings built into capital and O&M amounts**
- **Productivity as key strategy to be successful in IR**
- **Renew the company's culture of productivity and galvanize support at all levels of the organization**
- **Maintain the safety, reliability of supply at the lowest service cost**

Stakeholder Benefits of Productivity

Customers

- Just and fair rates
- Reliable service quality (customer relationship, safety, etc.)
- Potential to share in earnings

Shareholders

- Potential for earnings in excess of the allowed return
- Potential to absorb new requirements by building capacity now

Regulator

- Operational efficiency
- Value achievement

Employees

- Engagement
- Effectiveness

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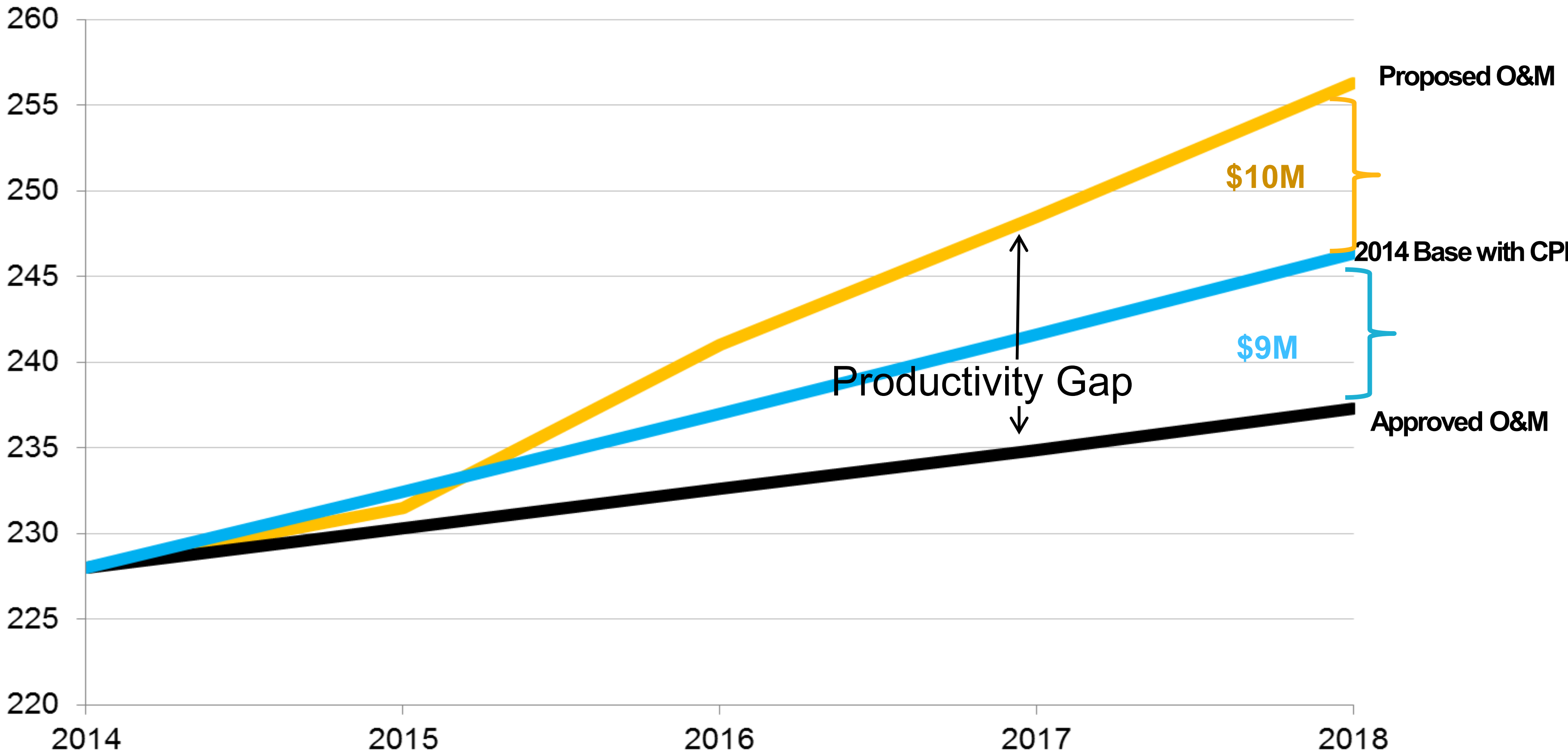
Productivity and the Custom IR Framework

- Embedded Productivity & Excluded Variable Capital Costs represent 20% of the total capital approved --- accepted in the IR decision
- O&M Reductions represent 10% of Total O&M approved

2014-2018	Core Capital Savings	"Other" O&M Savings
Embedded Productivity	$162 million	$ 172 million
Excluded Variable Capital	$ 264 million	
OEB Adjustment		$ 42 million
TOTAL	$426 million	$214 million

The O&M Gap – The Productivity Challenge

*** $ million – (excludes Customer Care/CIS, Pension & OPEB , and DSM)**



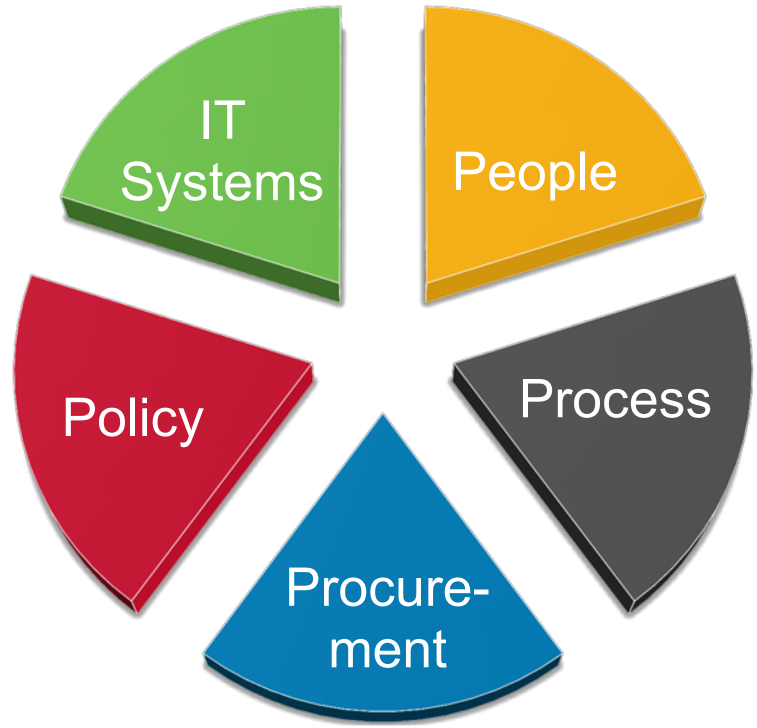
Renewing the Productivity Focus

- **Key messages across all levels to revitalize the productivity culture:**
  - Productivity is doing, achieving, or producing more with the same input, effort, or resources
  - Work smarter
  - Focus on what adds value
  - Productivity is key to the Company’s success in IR
  - Sustainability is a requirement

- **Productivity =** $\dfrac{Output}{Input}$

Areas of Focus

- Reviewed key areas with greatest potential for improvement or rationalization
- Certain areas easier to institute change than others
- Processes and systems require more complex, more cross-functional collaboration



2014 Activities

- Allocative efficiency as guiding principle
- Prioritization, assessment, and optimization carried out by:
  - Productivity Committee
  - Hiring review process
  - Capital Steering Committee

– Goal: instill equal organizational priority to drive the discipline and rigour needed to be successful

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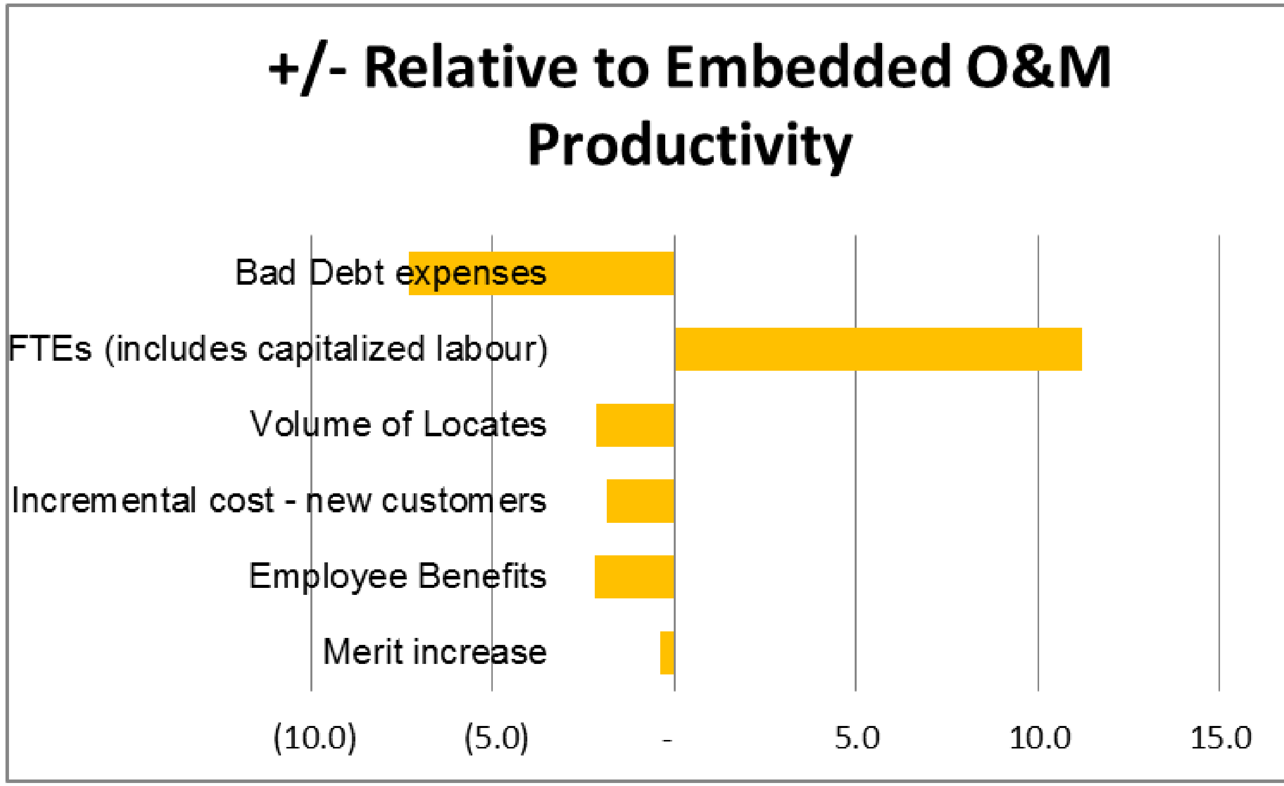
2014 Embedded Productivity (select work items)

- If full embedded productivity was actualized, value = 0
- Incremental safety & integrity work not isolated in reporting



Sustainable Productivity Examples – O&M

- **Productivity actions were pursued under each Director within the organization**

Labour Optimization	• Incremental to FTE reduction • Reduction in consultant costs & overtime	$1.0 million
Process Optimization	• eBill adoption	$1.1 million
Materials/Space/ Equipment Rationalization	• Facilities space optimization	$1.6 million
Policy Changes & Improvements	• Carbon Monoxide Alarm Response policy	$1.5 million

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Productivity and Performance Measurement

Productivity (KPMs)

- Operating Efficiency
- CustomerCare Efficiency
- Employee Efficiency
- Outside Services Efficiency
- Support Groups Metric
- Core Operations Metric
- Capital Overheads Metric
- Service Capital Metric
- Customer Capital Metric
- System Improvement Metric

Customer Relationship (SQRs)

- Customer Satisfaction Index
- Call Answering Service Level
- % Emergency Calls Resp. to within 1Hr
- Appointments Met within Designated Time
- Time to Reschedule Missed Appointments
- # Days to Reconnect Customer
- # Calls Abandon Rate
- Meter Reading Performance
- # Days to provide a Written Response

Operational Performance

- EHS: TRIF Rate
- # Excavation Damages per 1k locates
- Service Leaks Repaired per Mile of service
- Total # Grade 1 (A) leaks repaired during Yr.
- All Outages per 1k Customers

Financial Performance

- O&M per Customer ($)
- Return on Equity (%)
- Interest Coverage Ratios

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Productivity Indicators - 2014

		Trending			Trending
1	Total O&M Costs / # Customers		6	Total Core Operations O&M Costs / #km of Active Mains	
2	Total Customer Care Costs / # Customers		7	Total Departmental Labor + A&G Costs / Total Core Capital Spend	
3	Total Employee Related Costs / # Customers		8	Total Service Capital Costs / # Services installed	
4	Total Outside Services O&M Costs / # Customers		9	Total Customer Adds Capital Costs / # Customer Adds	
5	Total Support Groups O&M Costs / # FTEs		10	System Improvement Cost/ Kms of Plant Installed (mains + services)	

Green denotes better results or cost reductions relative to 2014 budget.

EGD's 2013 Baseline & 2014 Results (draft)

Operational Performance	2013	2014	Trending
1. Employees Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.03	
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	
Customer Relationship Performance	**2013**	**2014**	**Trending**
1. Overall Customer Satisfaction Index	632	629	
2. Percentage of Emergency Calls Responded to within One Hour (SQR)	96%	97%	
3. Appointments Met within the Designated Time Period (SQR)	94%	95%	
4. Time to Reschedule a Missed Appointments (SQR)	95%	96%	
5. Number of Days to Reconnect a Customer (SQR)	93%	94%	

Green denotes better results in 2014 relative to 2013.

Update on Total Factor Productivity (TFP) Benchmarking Study

- In-house regulatory scan of TFP Benchmarking in Ontario and other recent developments in North American jurisdictions

- Enbridge's commitment
  - Benchmarking study with third-party consultant
  - Consultative to review Enbridge's proposed benchmarking methodology with intent of filing an acceptable approach with the OEB
  - Final report to be filed at end of CIR period

- Next steps
  - Secure benchmarking consultant
  - Engage consultative in 2016

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Gas Supply

Andrew Welburn
Don Small

Objective of Gas Supply Planning

- To develop a portfolio of natural gas supply, transportation and storage assets in order to provide for the safe, reliable and cost effective delivery of natural gas
- A Gas Supply Plan is developed base on the principles of reliability, flexibility, diversity and cost subject to a given level of risk

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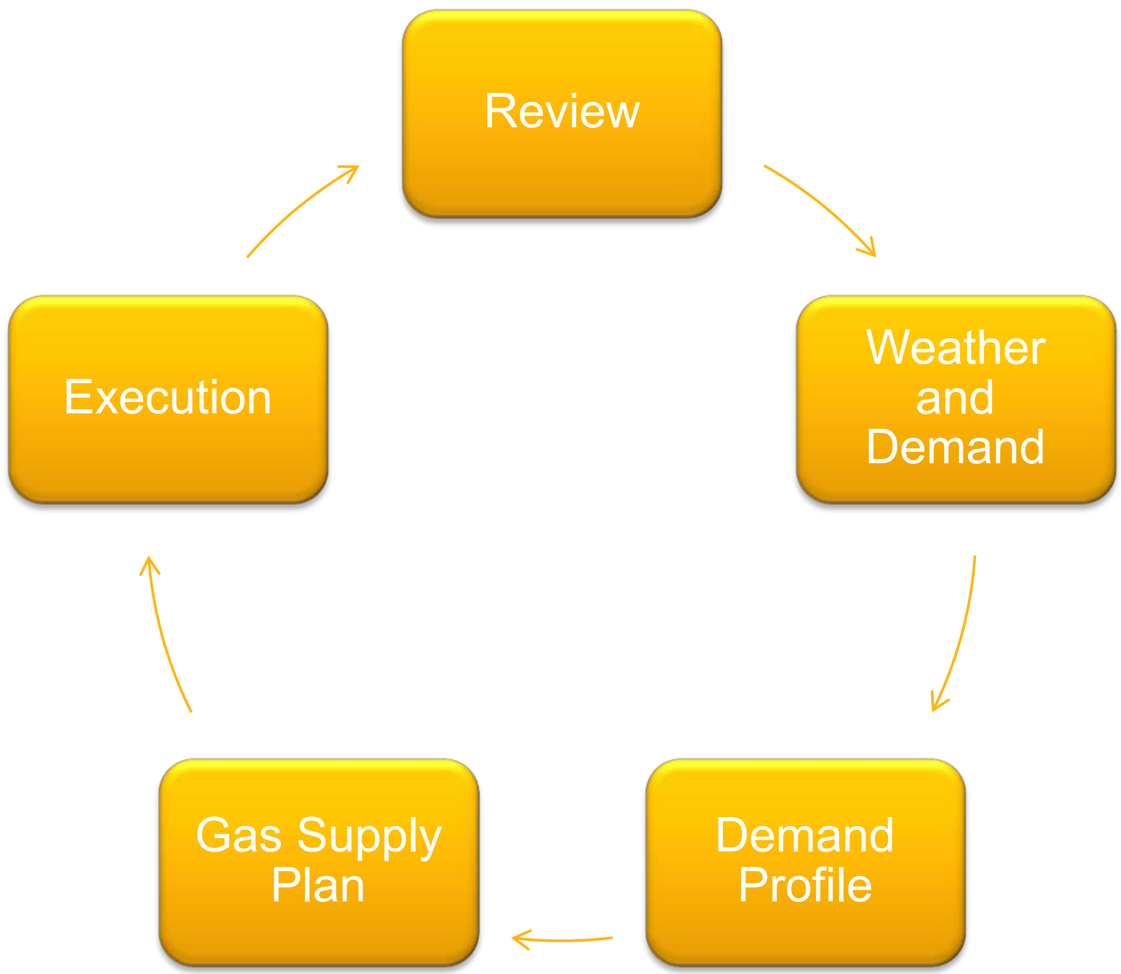
Gas Supply Planning Cycle

The agenda for this presentation will proceed through the gas supply planning cycle.



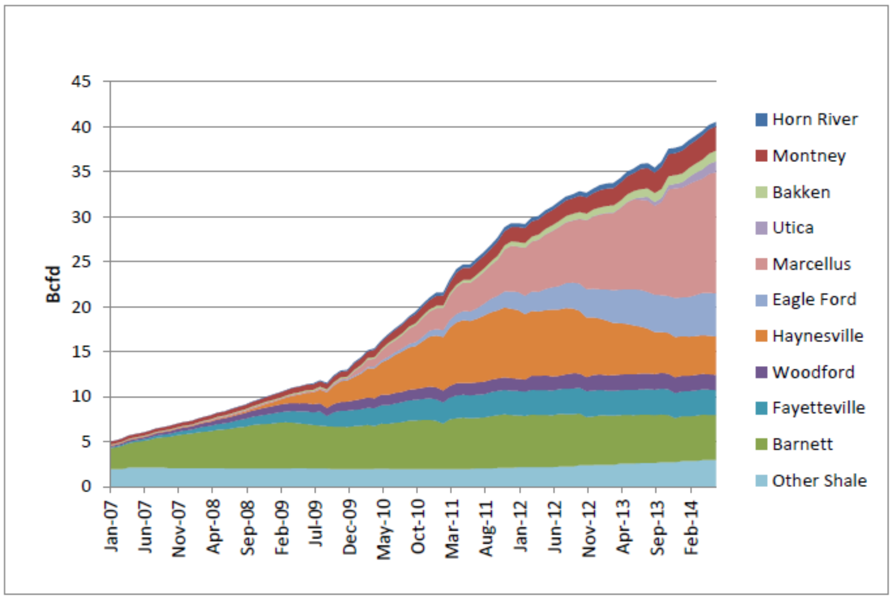
Review of changes in the natural gas marketplace

First step involves examining trends and considerations that will inform the gas supply planning process

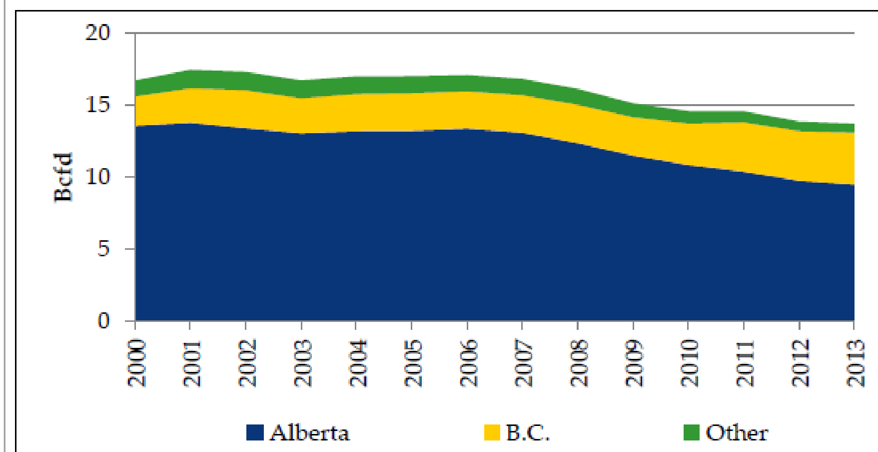
North American Natural Gas Supply Basins Trends

One significant trend is continued growth in shale gas production, particularly in the Appalachian Basin

– Current Marcellus/Utica production ≈ peak Western Canadian Sedimentary Basin production since turn of the century (*and production is still growing!*)



Source: Navigant / LCI Energy Insight



Source: NEB

Location of North American Natural Shale Production

Marcellus and Utica natural gas production located in close proximity to Ontario

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Provincial Regulatory Considerations

Ontario Energy Board

Ontario Energy Board proceedings impacting current and future gas supply plan development

– EB-2012-0433, EB-2013-0074 and EB-2012-0451 (*GTA and Parkway Projects*)
  - Market access to Dawn and Niagara for the Greater Toronto Area
  - Reduced reliance on TransCanada long-haul transportation to supply the Greater Toronto Area

– EB-2014-0323 (*Dawn Access Settlement*)
  - Direct Purchase customers in Greater Toronto Area gain access to Dawn effective November 2015
  - Remainder of Direct Purchase customers gain access to Dawn effective November 2017

– EB-2014-0039 and EB-2014-0191 (*April and October QRAMs*)
  - High winter demand results in Incremental gas supply costs
  - Concerns raised with level of risk incorporated into the gas supply plan

– EB-2014-0276 (*2015 Rate Adjustment*)
  - New storage deliverability targets proposed to reduce reliance on late season gas procurement

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National Regulatory Considerations

National Energy Board
Office national de l'énergie

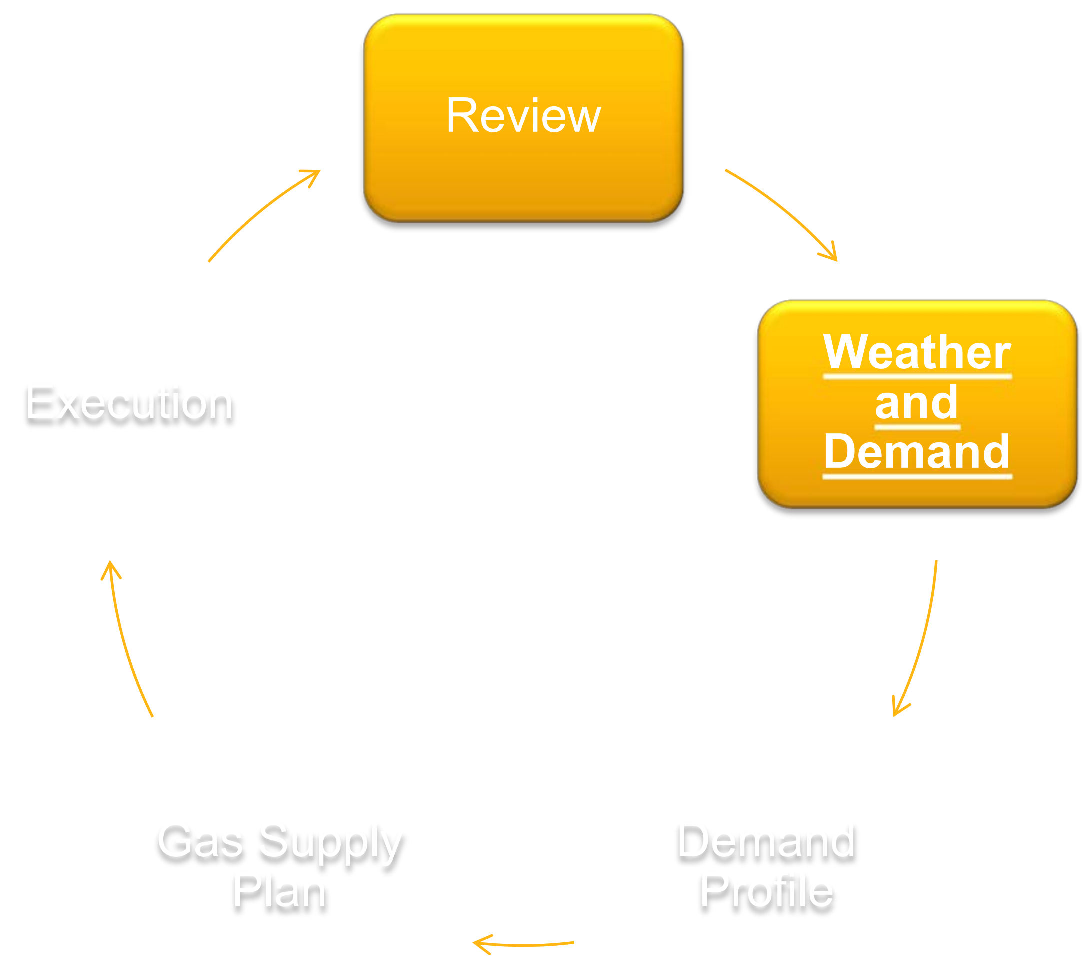
National Energy Board proceedings impacting current and future gas supply planning

- RH-03-2011 (*Restructuring Proposal*)
  - Transportation toll stability
  - Incremental market access to Dawn restricted due to concerns of revenue recovery
  - Short Term Firm Transportation (STFT) no longer an economical transportation option
- TransCanada's Energy East Project and Eastern Mainline Project
  - Proposed elimination of discretionary transportation capacity for eastern Ontario, Quebec, and northeast United States
  - Portion of STFT replaced with Non-Renewable Firm Transportation
- RH-01-2013 (*Tariff Proposals*)
  - Renewal notice increased from 6 months to 2 years
- MH-01-2013 (*Abandonment Set Aside and Collection Mechanisms*)
  - Abandonment surcharge added to transportation tolls
- RH-01-2014 (*2013-2030 Settlement*)
  - Transportation toll stability
  - Market access to Dawn provides alternative to Non-Renewable Firm Transportation
  - STFT remains an uneconomical transportation option

ENBRIDGE

Development of annual weather and demand forecast

Second step in the cycle is determining annual budget degree days and demand



Budget Demand

Annual budget degree days and demand determined by Economic & Market Analysis

- Budgeted demand is a key input into the gas supply planning process
- Prepared on an annual basis using methodologies approved by the Board
  - Budget degree days for Central, Niagara, and Eastern region based on separate methodologies using actual Environment Canada degree days
  - General service budget demand forecast based on customer unlock budget and normalized average use
  - Contract market budget demand forecast based on grass roots approach for existing customers and probability-weighted approach for expected customers

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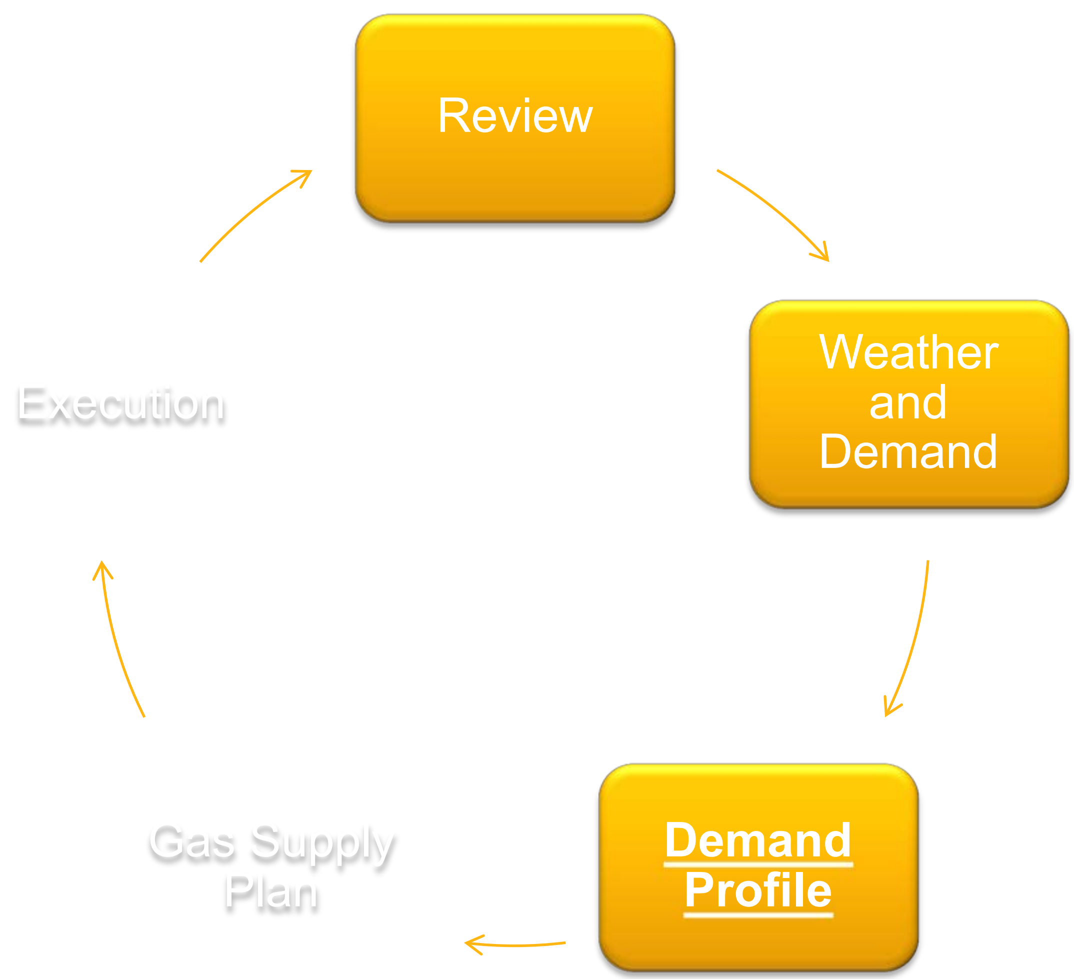
Development of daily demand profiles

Third step in the cycle is converting heating degree days and demand from annual to daily profiles

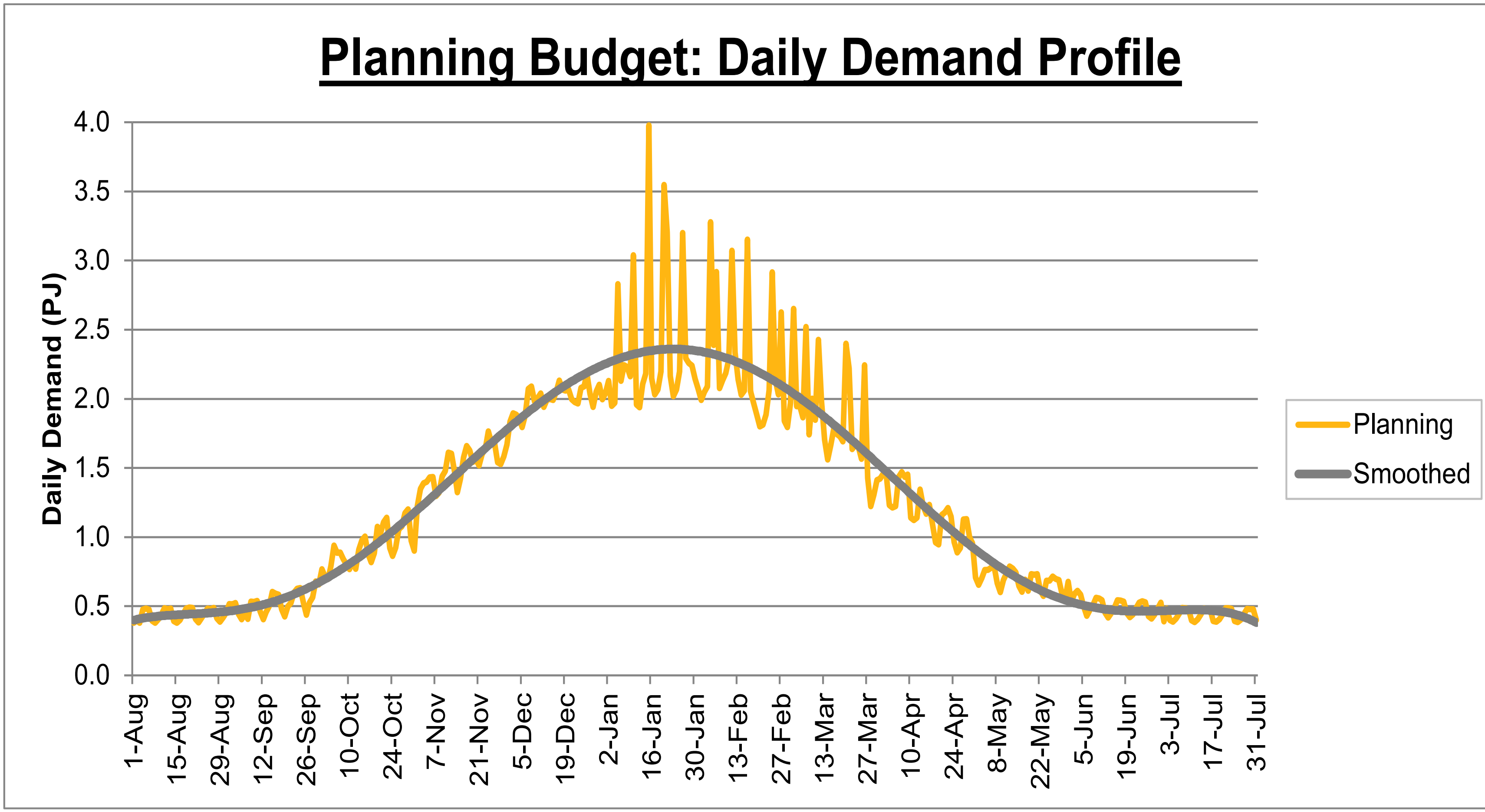


Establishment of Demand Profiles

Demand profiles are determined using Board approved Design Criteria

- The annual budget is distributed into a daily profile
- Daily profile used to establish a gas supply plan
- The daily profile incorporates Board approved Design Criteria
- The Board approved Design Criteria includes the following elements:
  - 1 in 5 recurrence interval (based on a log-normal distribution) for Peak and Multi-Peak degree days
  - Peak Day Heating Degree Days are:
    - 41.4 in the Central region
    - 48.2 in the Eastern region
    - 38.8 in the Niagara region
  - 18 Multi-Peaks over the months of January, February, and March for each of the Central, Niagara, and Eastern regions

Resulting Demand Profile



Importance of Design Criteria

There is a trade-off between budgeted gas costs and the stability of QRAM adjustments

Design Criteria	Demand Variance Above Budget	
	Minimal	High
Risky	Low Budget Cost Neutral Execution Cost	Low Budget Cost High Execution Cost
Conservative	High Budget Cost Neutral Execution Cost	High Budget Cost Low Execution Cost

– The level of risk assumed in the Design Criteria will, in part, determine the range of actual demand that can be managed by the gas supply plan

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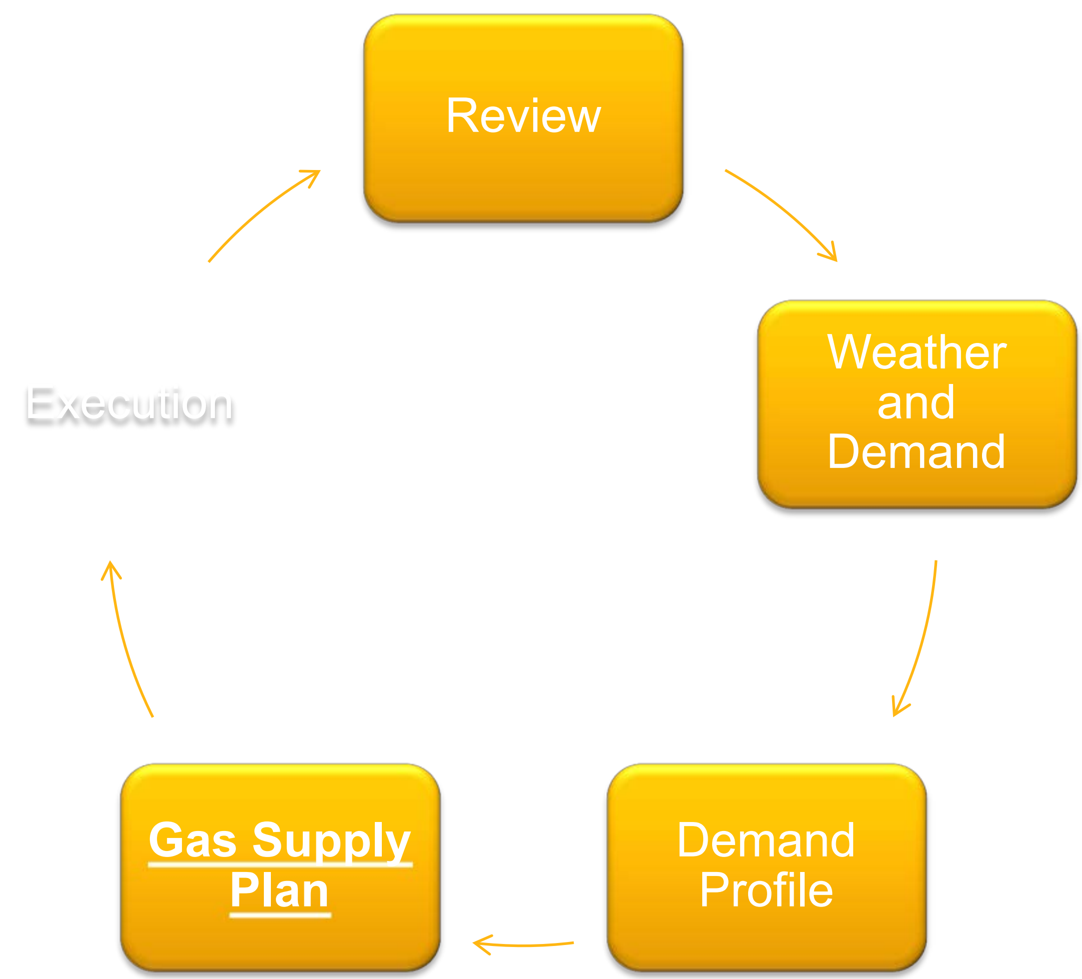
Development of optimal gas supply plan

Fourth step in the cycle is determining the assets required for the gas supply plan



The Gas Supply Plan

Establishment of the assets and how to use them to in an optimal way to meet budget demand

– The gas supply plan is developed to ensure that the supply, storage and transportation assets required to meet peak day demand are acquired

– Asset requirements are assessed with 4 gas supply planning principles:
  - Reliability – Supplies are sourced from established liquid hubs and delivered via firm transportation contracts
  - Diversity – Supplies are procured from multiple procurement points and transported to market through several different paths
  - Flexibility – Differentiated supply procurement patterns and operational flexibility through service attributes and contract parameters
  - Landed Cost – Gas supply costs must be balanced with the other principles and the gas supply plan must ensure competitive pricing for customers

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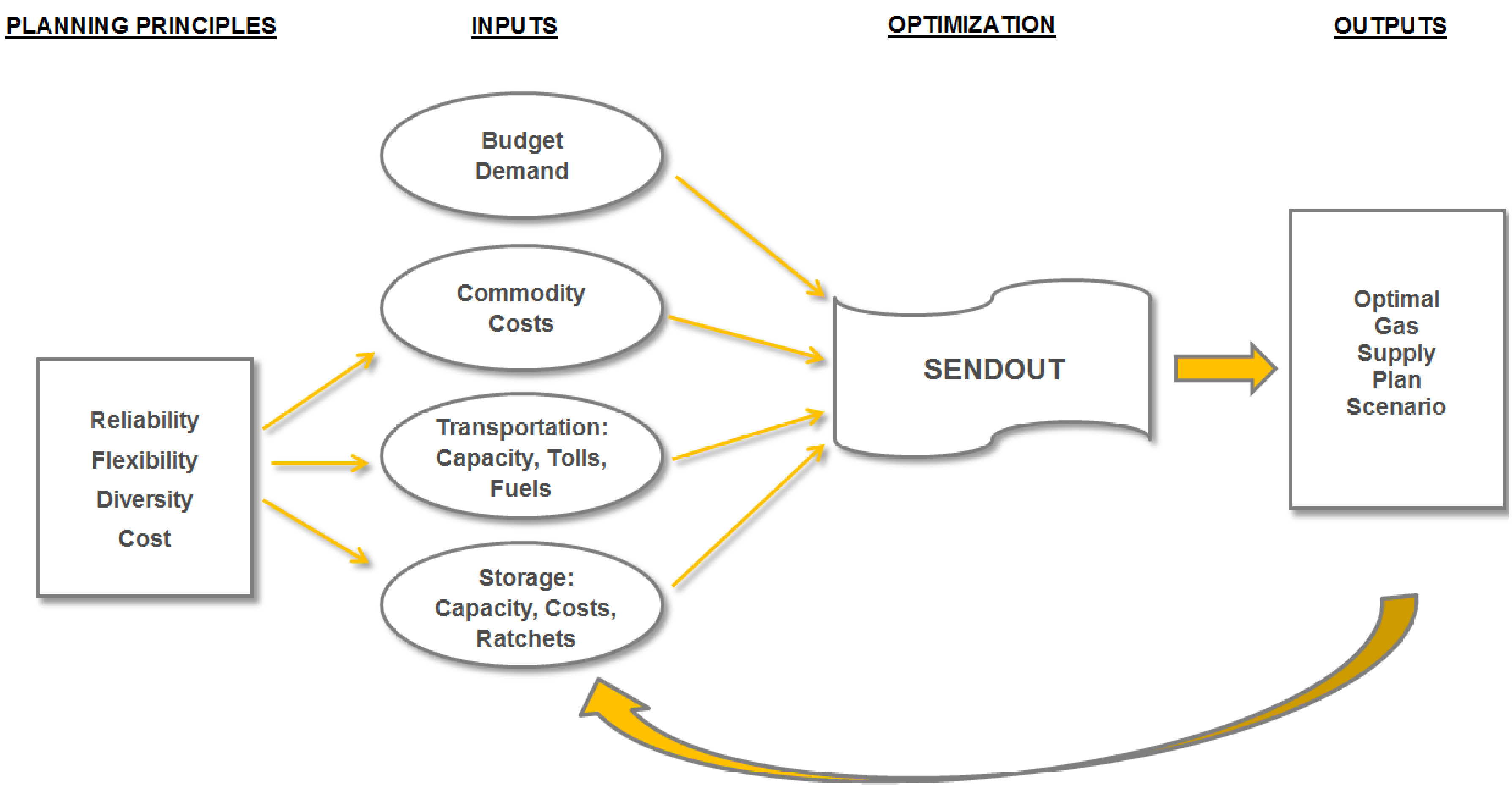
Gas Supply Plan Optimization and Evaluation

SENDOUT used to optimize and evaluate gas supply plan scenarios



Change to 2015 Storage Management Plan

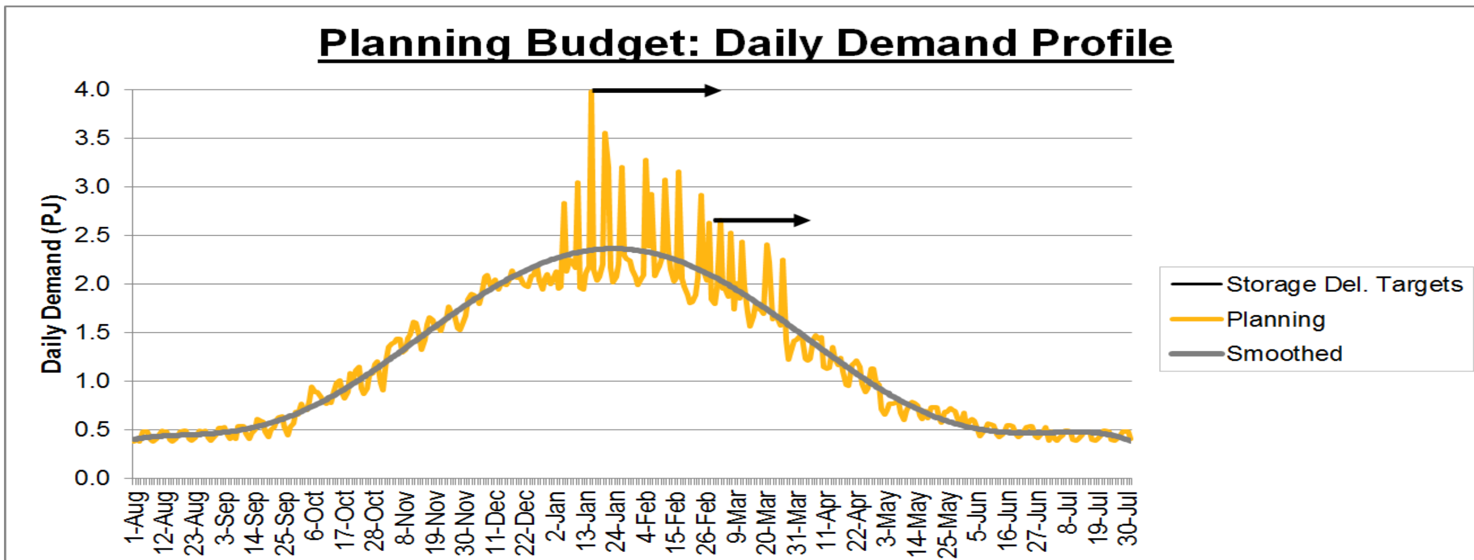
Colder than budget weather during winter of 2013/2014 resulted in increased gas supply execution costs

– What changes were made?

- January peak demand storage deliverability held constant to end of February
- March peak demand storage deliverability held constant to end of March

– How does this change impact the gas supply plan?

- Increases gas supply budget costs by shifting some gas supply purchases from summer to winter
- Reduces risk of increased gas supply execution costs if winter demand is higher than budget



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2015 Gas Supply Plan Budget

Item #	2014 Budget Peak Day Demand GJ's	Column 1 CDA	Column 2 EDA	Column 3 Total	2015 Budget Peak Day Demand GJ's	Column 4 CDA	Column 5 EDA	Column 6 Total
1.	Demand	3,288,088	673,262	3,961,350	Demand	3,303,548	674,042	3,977,590
2.	Less Curtailment	(133,995)	(28,705)	(162,700)	Less Curtailment	(83,874)	(33,259)	(117,133)
3.	Net Peak Day Demand	3,154,093	644,557	3,798,650	Net Peak Day Demand	3,219,674	640,783	3,860,457
4.	TCPL FT Capacity	271,468	370,627	642,095	TCPL FT Capacity	404,538	390,627	795,165
5.	TCPL STFT	-	-	-	TCPL STFT	-	-	-
6.	TCPL Short Haul	151,818	114,000	265,818	TCPL Short Haul	158,720	114,000	272,720
7.	TCPL STS	369,464	80,611	450,075	TCPL STS	369,465	80,611	450,076
8.	Ontario T-Service	300,354	26,576	326,930	Ontario T-Service	243,353	5,718	249,071
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	182,738	-	182,738	Delivered Service	167,739	-	167,739
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,506	52,754	158,260
12.	Total Supply	3,156,374	644,567	3,800,941	Total Supply	3,224,348	643,710	3,868,058
13.	Sufficency/(Deficiency)	2,281	10	2,291	Sufficency/(Deficiency)	4,674	2,927	7,601

Filed: 2014-11-28
EB-2014-0276
Exhibit D1
Tab 2
Schedule 6
Page 1 of 1

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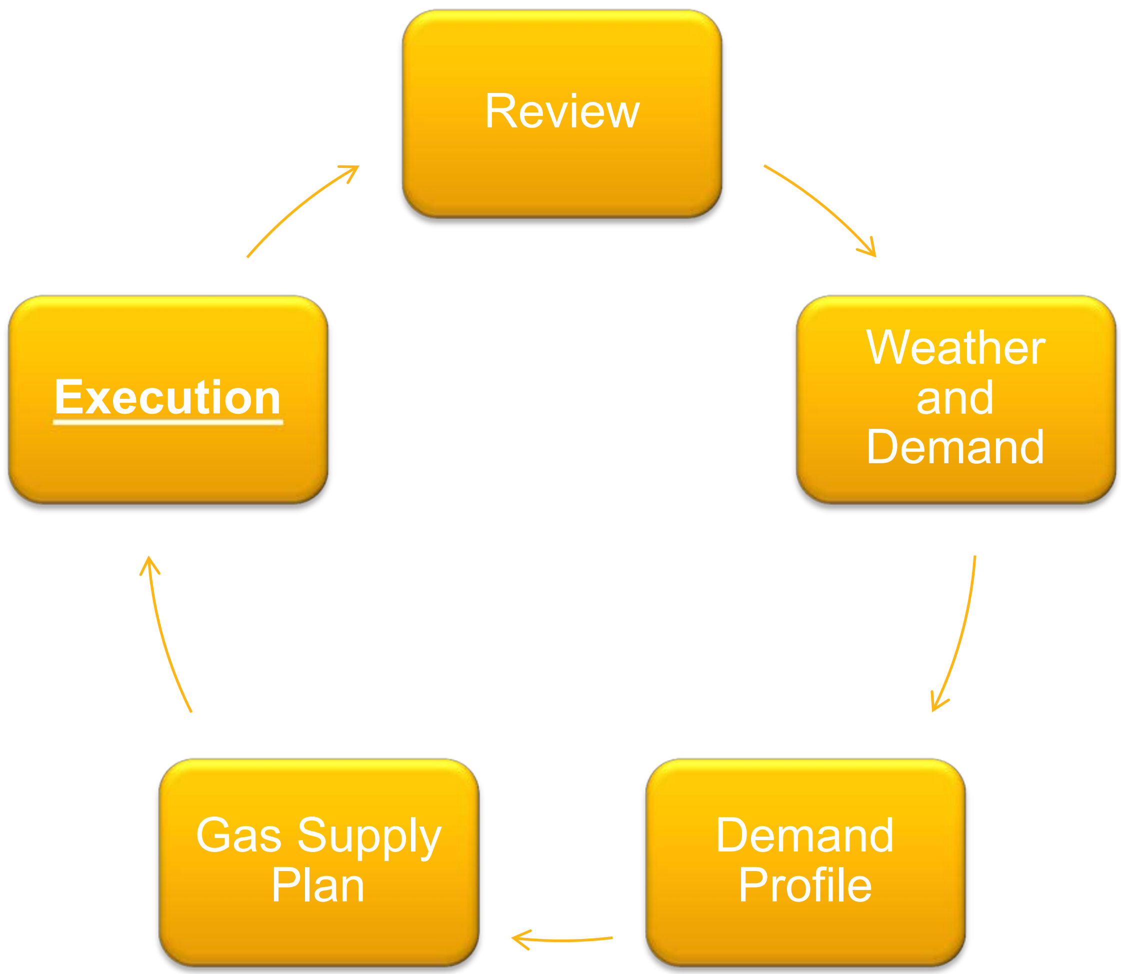
Execution of the gas supply plan

Fifth step in the cycle is dealing with variances between budget and actual weather and demand



Execution of Gas Supply Plan

The Gas Supply Plan is closely monitored and managed throughout the year by a diverse team

– Operational planning meetings are conducted on a frequent basis to determine how weather and demand variances from budget are to be managed

– Frequency of operational planning meetings varies throughout the year
  - During winter period meetings are conducted on a weekly basis at a minimum
  - During summer period meetings are typically conducted on a bi-weekly basis

– Operational planning meetings chaired by Director Energy Supply and Policy and supported by a diverse cross-functional team
  - Gas Supply Planning
  - Gas Supply Procurement
  - Gas Costs and Budgets
  - Gas Control Operations
  - Gas Storage Operations
  - Distribution Planning
  - Key Customer Contract Management

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Scope of Operational Planning Meetings

The Gas Supply Plan is closely monitored and managed throughout the year

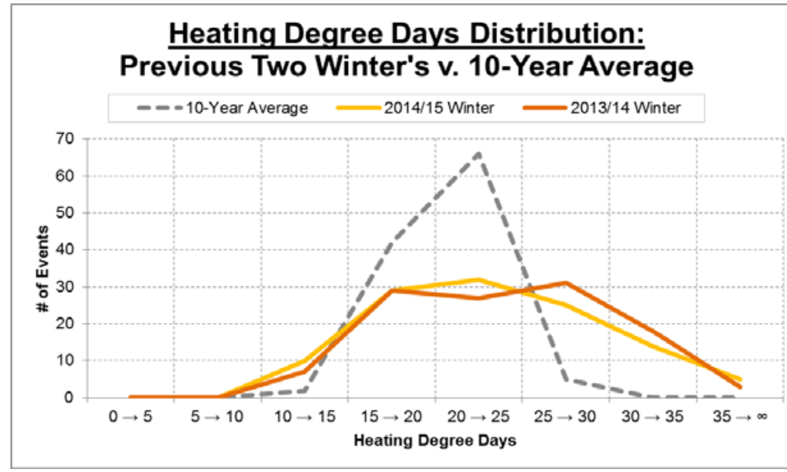
- Operational planning meetings closely reviews and monitors factors impacting the gas supply plan
  - Actual and budget year-to-date variances in weather and demand
  - Short term (7 day) and medium term (1 month) weather forecasts
  - Revised gas supply plan outlook that takes into account actual and short term demand forecast
  - Operational updates from Gas Control
  - Operational updates from Gas Storage
  - Procurement strategies
  - Balancing requirements for direct purchase customers
- Outcomes from the operational planning meetings include
  - Direction on any natural gas procurement including Request for Proposal (RFP) requirements to meet current and forecasted demand
  - Direction on customer curtailment requirements
  - Direction on make-up and suspension balancing availability for direct purchase customers

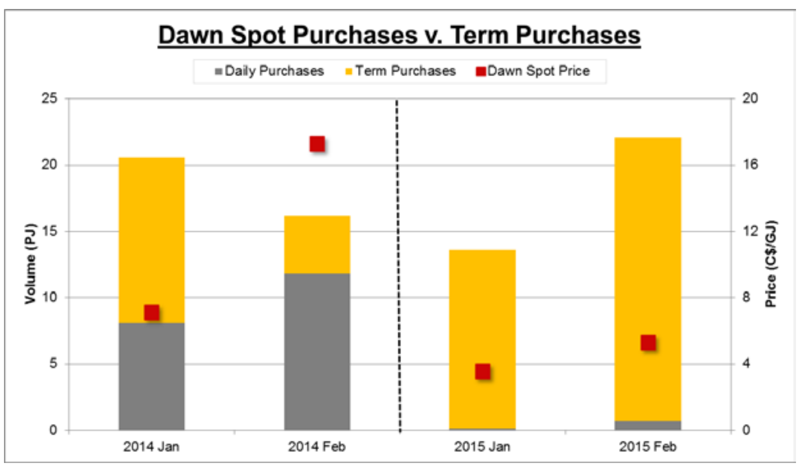
Review of changes in the natural gas marketplace

Sixth step in the cycle is examining considerations leading into the 2016 gas supply planning cycle

Review of Winter of 2014/2015

- Winter 2014/2015 weather exceptionally colder than normal and similar to Winter 2013/2014
- Winter 2014/2015 QRAM adjustment not similar to Winter 2013/2014





- Change in storage deliverability targets and longer term weather forecasts enabled shift in gas procurement strategy
- Change in procurement strategy reduced exposure to Dawn daily pricing

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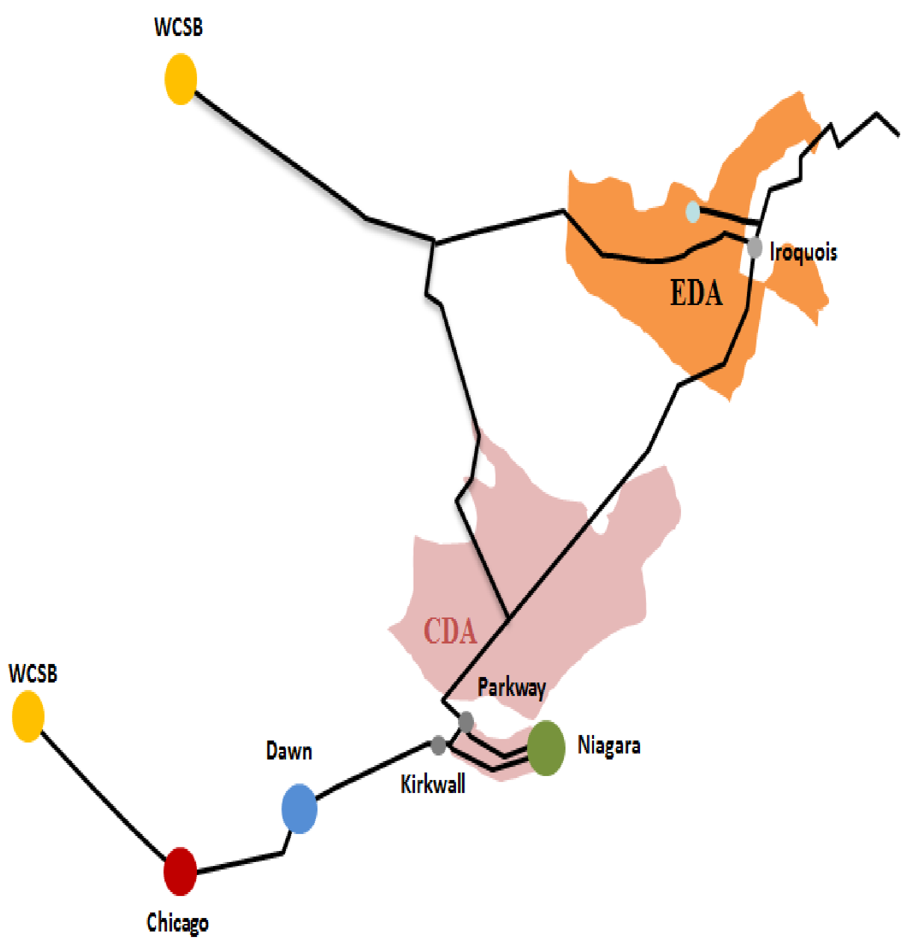
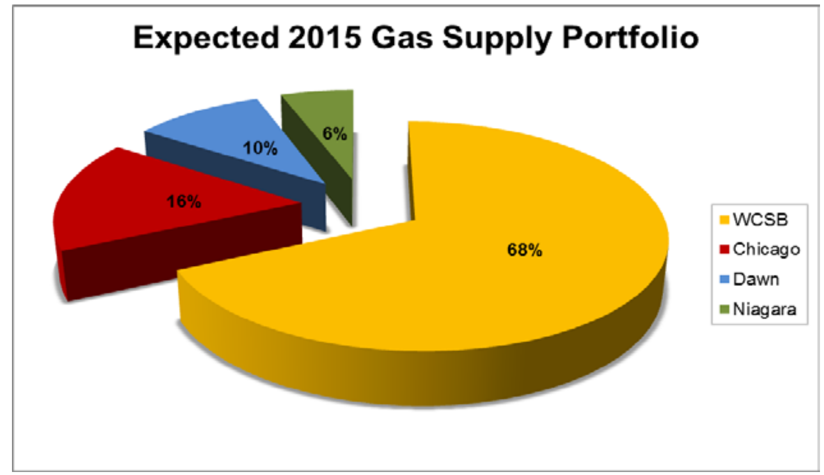
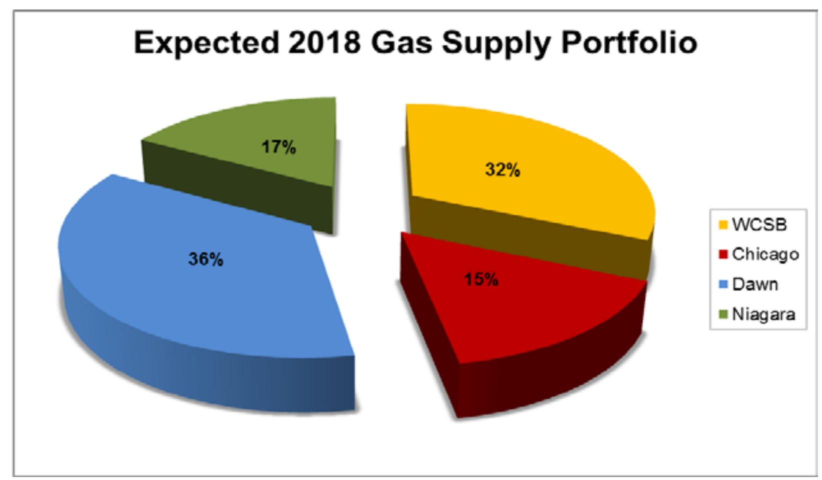
Supply Portfolio Diversification

Market access to Dawn and Niagara has diversified our supply basin portfolio







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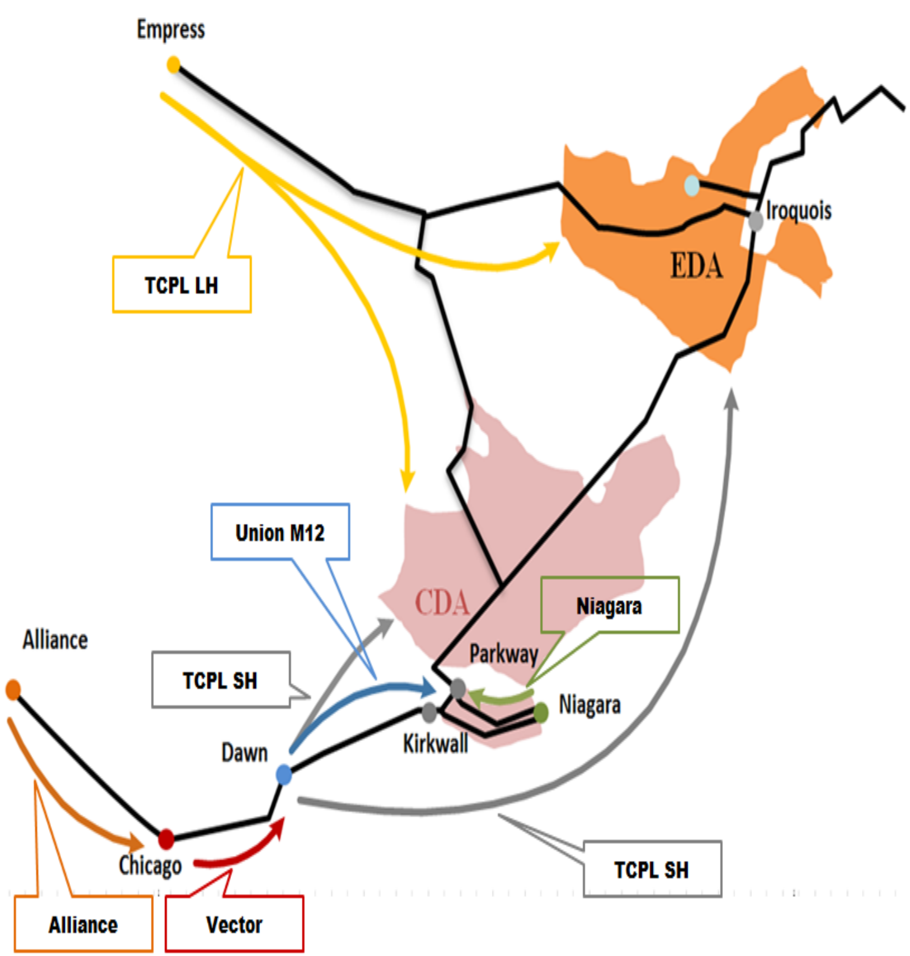
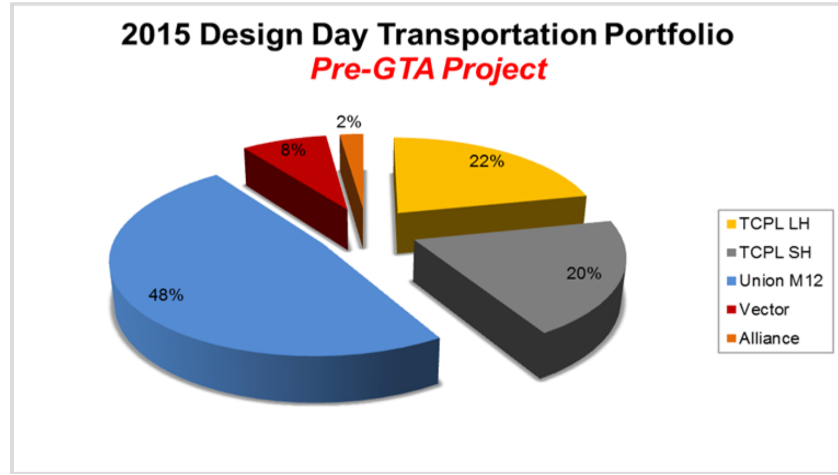
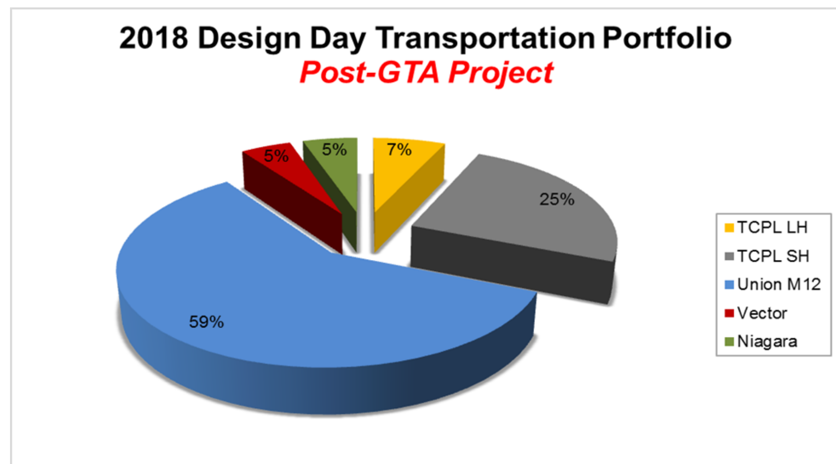
Transportation Portfolio Diversification

Market access to Dawn and Niagara has diversified our transportation portfolio







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Post 2016 Storage Management

- 2016 Gas Supply Plan expected to follow 2015 Gas Supply Plan strategy including new method to establish storage deliverability targets
- Incremental storage assets being evaluated for post-2016 Gas Supply Plan
- Preliminary analysis indicates 16 Bcf of incremental storage required

Incremental Storage Requirements*: Various Design Criteria (Normal Distribution)

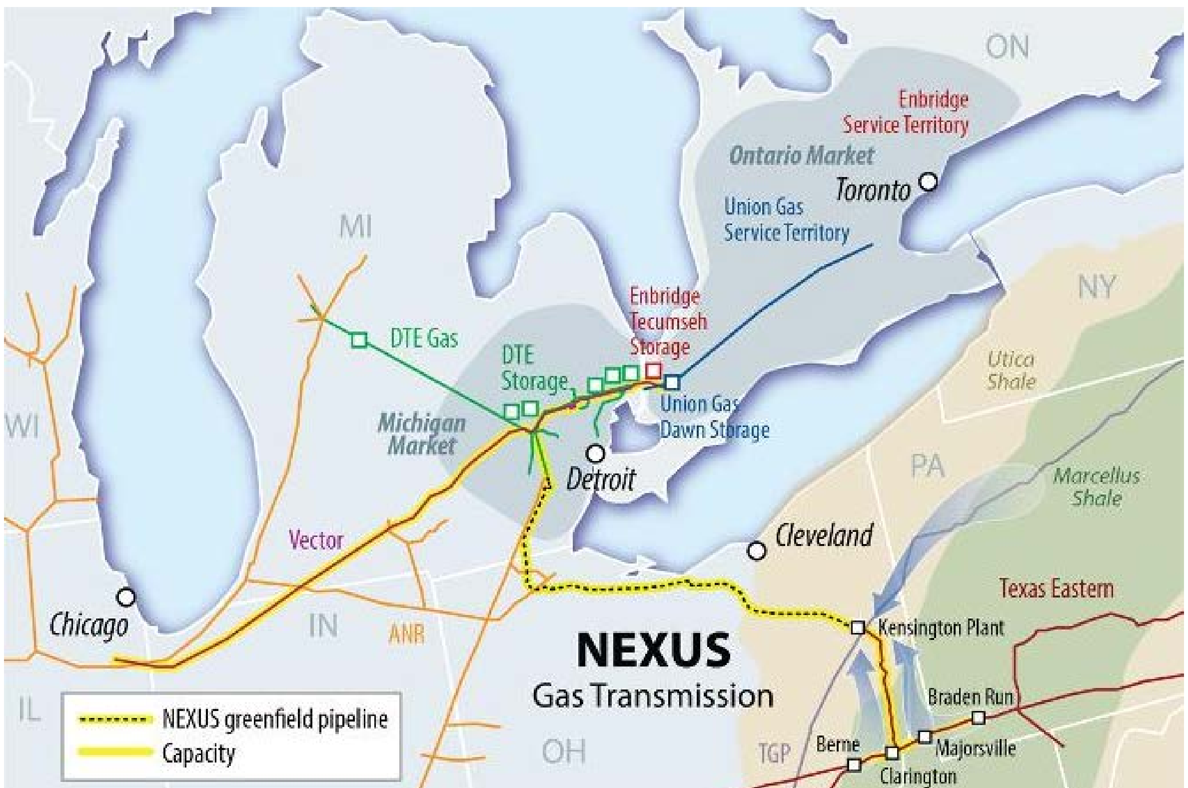
Design Criteria Recurrence Interval	Associated Probability of Being ≥	Central Weather Zone Winter HDD	Incremental Storage Requirement (Bcf)
Current 1 in 2	50%	2,945	-
1 in 5	20%	3,207	9
1 in 10	10%	3,303	14
1 in 15	≈6%	3,364	16
Peak Day Equivalent	5.7%	3,369	16
1 in 20	5%	3,384	21

* Analysis based on 2015 budget

NEXUS

Precedent Agreement pending approval of pre-approval application by Ontario Energy Board

- Precedent Agreement (PA) signed for capacity on NEXUS in December 2014
- PA conditioned on Board pre-approval of 15 year contract costs
- Pre-approval application expected to be filed with the Board in April 2015



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Dawn Access for Direct Purchase Customers

Approximately 85% of direct purchase deliveries will be made at Dawn starting in 2017

- Phase 1 comes into effect on November 1, 2015
  - Available only to existing Ontario Transportation Service customers in the CDA
  - 2 year assignment of existing Dawn to Enbridge CDA transportation
  - Apportionment of assignment capacity calculated to be 122 TJ/d
  - Election process closes mid-April 2015
- Phase 2 comes into effect on November 1, 2017
  - Available to all customers
  - Customer delivery at Dawn and Enbridge manages transportation to delivery area
  - Approximately 85% of current direct purchase capacity has elected to deliver at Dawn
- Dawn access has been requested by unbundled customers
  - Discussions expected later in the year

ENBRIDGE

Closing Remarks

Andrew Mandyam
Kevin Culbert

Closing Remarks

- Shared historical information:
  - Year end financials
  - CAPEX
  - O&M
  - Updates on various reports as part of our commitment
- Upcoming activities
  - Gas Supply Planning and Community Expansion

2014-2015 Gas Supply Plan Memorandum

Enbridge Gas Distribution Inc.

April 2015

Table of Contents

1. Introduction

1.1 Purpose

On July 17, 2014 the Ontario Energy Board ("Board") released its Decision with Reasons in relation to the 2014 to 2018 Custom Incentive Regulation plan ("CIR") application filed by Enbridge Gas Distribution Inc. ("Enbridge" or the "Company") under case number EB-2012-0459 ("EB-2012-0459 Decision"). Included in the EB-2012-0459 Decision were a number of reporting requirements that Enbridge had committed to provide. One of those reporting commitments was the provision of a Gas Supply Plan Memorandum. This memorandum was to be provided on an annual basis over the term of the CIR plan and would include[1]:

1. *a summary of the current natural gas market situation;*
2. *the results of the design day demand forecast with a discussion of the underpinning assumptions;*
3. *an overview of the current gas supply portfolio;*
4. *the identification of near term portfolio decisions and a description of how the Enbridge strategy for the specific portfolio decision conforms to the gas supply planning principles; and*
5. *a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g. RH-003-2011); physical infrastructure projects that will likely impact Enbridge; and the implications associated with gas supply basins.*

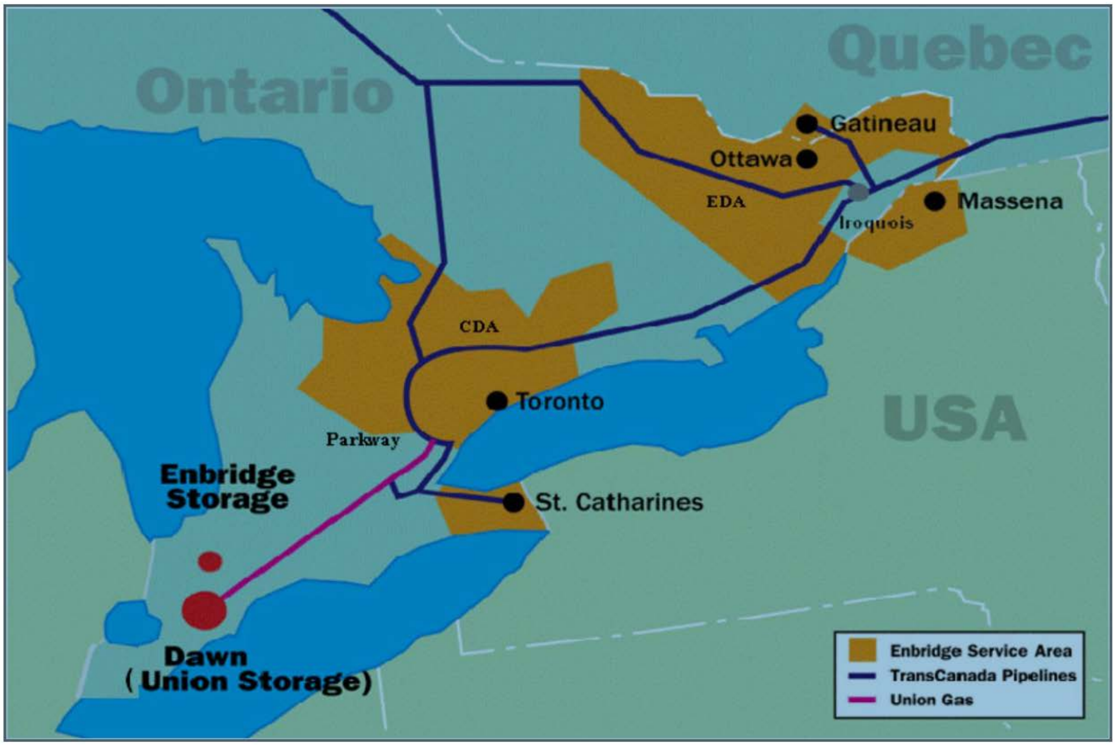
This document has been prepared in response to the reporting requirement for a Gas Supply Plan Memorandum as determined in the Board's Decision.

1.2 Company & Franchise Area Description

Enbridge is a natural gas distribution company with its head office in the City of Toronto. Enbridge is the largest natural gas distribution company in Canada and provides natural gas distribution services to over 2 million customers. It is among the fastest growing natural gas distribution companies in North America with approximately 40,000 largely temperature sensitive customers being added across its franchise each year. The Enbridge franchise area spans central and eastern Ontario and includes the Greater Toronto Area ("GTA"), the Niagara Peninsula, Barrie, Midland, Peterborough, Brockville, Ottawa, Gatineux via Gazifère Inc., and other Ontario communities (collectively the "Enbridge System") as shown in Figure 1.

[1] EB-2012-0459 Decision with Reasons dated July 14, 2014 page 80.

Figure 1 – Enbridge Franchise Map

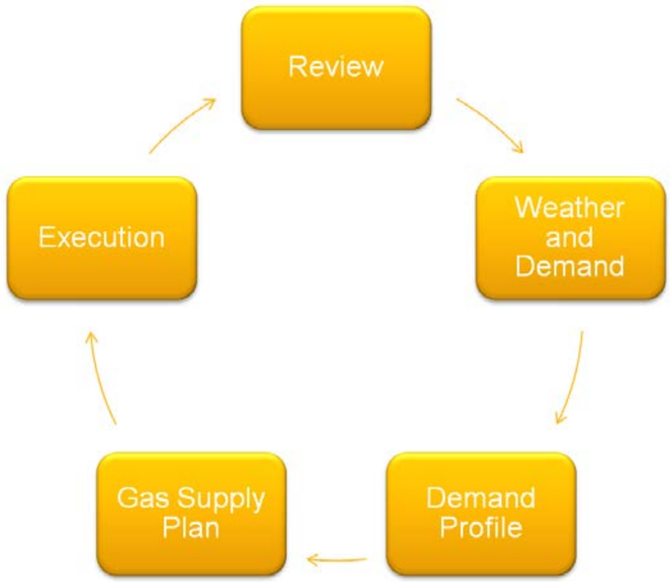


Enbridge does not have access to any significant local natural gas production within its franchise area. Less than 1% of its annual gas supply requirement is locally produced within Ontario. In order to provide safe, reliable, and cost effective delivery of natural gas to its customers, Enbridge procures supply from basins and liquid hubs within North America. These supplies are transported to the markets served by Enbridge through contracted capacity on several upstream natural gas transmission systems that ultimately connect to the Enbridge franchise area and storage facilities at Tecumseh and the Dawn hub in Ontario.

1.3 Gas Supply Planning

The objective of gas supply planning is to develop a portfolio of natural gas supply, transportation, and storage assets that provide for the safe, reliable, and cost effective delivery of natural gas to customers throughout the calendar year. A gas supply portfolio is structured first and foremost to meet demand for natural gas on peak day (i.e. the day of highest demand) along with seasonal demand for natural gas throughout the winter and summer months. The process of establishing the gas supply plan is conducted annually. The resulting gas supply plan is filed with the Board as part of Enbridge's annual rate adjustment applications. Establishment and execution of the gas supply plan is summarized in Figure 2 as a cycle of phases.

Figure 2 – Gas Supply Planning Cycle



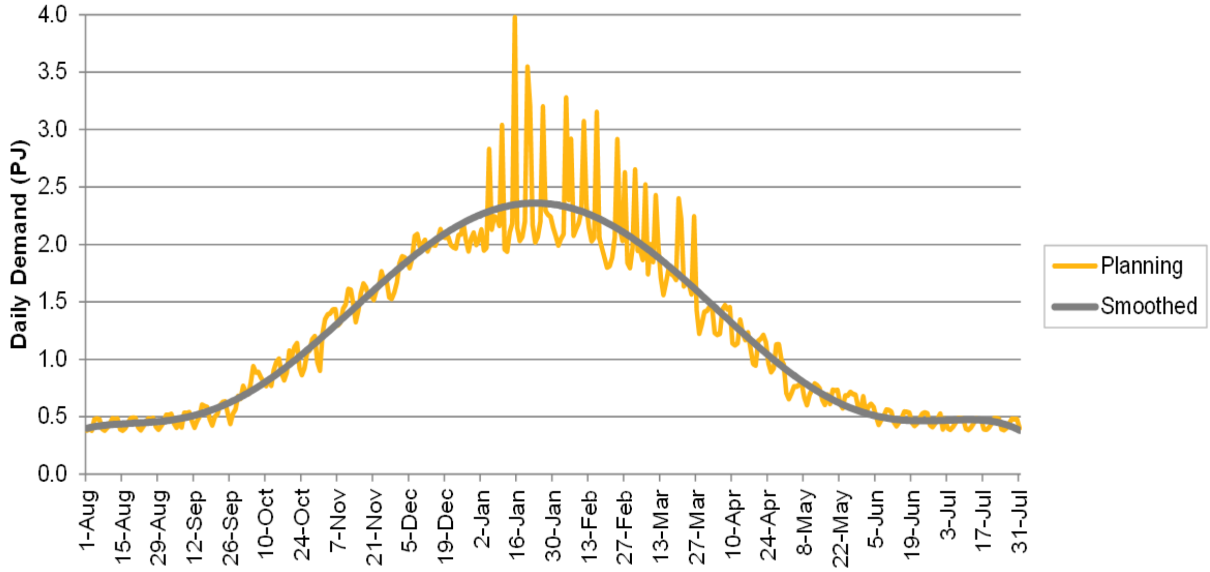
The cycle begins with a review of recent and expected future market conditions. The North American natural gas market is evolving at a very rapid pace. Natural gas production from shale formations has created new procurement opportunities and lead to the development of new and repurposed transportation pipelines across the integrated North American natural gas grid. This is especially so in the case of the Northeast United States where natural gas production is now equivalent to production from the WCSB.

The annual demand budget is developed in the weather and demand phase. Using Board approved methodologies, annual demand is forecast utilizing projected degree days, customer additions, information from large volume customers and other economic variables. Once the annual demand budget is provided to Energy Supply and Policy, development of the gas supply plan for the upcoming test year can begin.

The demand profile phase distributes the annual demand budget into a daily demand profile. When establishing the daily profile, Board approved Design Criteria[2] are used. These Design Criteria distribute annual demand according to seasonal weather patterns. Also included are peak day demand and near peak demand conditions. In Enbridge's Design Criteria the former is referred to as peak day and the latter are referred to as multi-peak days. The magnitude of the peak day and multi-peak days are determined by the weather conditions contained in the Design Criteria. These weather conditions were statistically determined using a 1 in 5 recurrence interval based on a log-normal distribution. When the Design Criteria are applied the resulting daily demand profile is used in developing the gas supply plan as illustrated in Figure 3.

[2] Current Design Criteria was approved by the Board as part of EB-2011-0354 and includes peak and 18 multi-peak heating degree days based on a 1 in 5 recurrence interval of weather conditions over a log-normal distribution.

Figure 3: Illustrative Daily Demand Profile



The level of risk, as measured by the recurrence interval, assumed in the Design Criteria has a significant impact on the development of the demand profile and subsequently the gas supply plan. A more conservative level of risk (i.e. a longer recurrence interval) will result in a gas supply plan that requires higher upfront budget costs to procure storage and transportation assets and will mitigate the need to procure incremental commodity and transportation assets should actual demand exceed budgeted demand. The converse is true when a less conservative approach (i.e. a shorter recurrence interval) is used to develop the gas supply plan. Figure 4 provides a qualitative assessment of cost impacts on a gas supply plan resulting from different levels of risk assumed in the Design Criteria.

Figure 4: Design Criteria Risk Matrix

Design Criteria	Demand Variance Above Budget	
	Minimal	High
Risky	Low Budget Cost Neutral Execution Cost	Low Budget Cost High Execution Cost
Conservative	High Budget Cost Neutral Execution Cost	High Budget Cost Low Execution Cost

Once the demand profile is established, the gas supply plan can be developed. The gas supply plan includes a portfolio of natural gas supply, transportation and storage assets used to meet demand. The gas supply plan is developed and assessed using four gas supply planning principles:

- *Reliability* – Enbridge is the "supplier of last resort" and as a result supplies are sourced from established liquid hubs and transported to the markets served by Enbridge via firm transportation contracts in order to mitigate delivery interruption;
- *Diversity* – Mitigates reliability and cost risks by procuring supplies from multiple procurement points and transporting supplies to market and/or storage through several different paths;
- *Flexibility* – Manages shifting demand requirements through differentiated supply procurement patterns and provides operational flexibility through service attributes and contract parameters; and
- *Landed Cost* – Balances gas supply costs with the other principles and ensures low cost natural gas supply for customers.

The gas supply planning principles are taken into consideration when gas supply plans are developed. The gas supply plan is evaluated through an iterative process utilizing a modeling application called SENDOUT to minimize overall supply portfolio costs. The resulting gas supply plan is evaluated using the gas supply planning principles.

Once the gas supply plan is established, the execution phase of the cycle takes place. Decisions related to the execution of the gas supply plan are made during operational planning meetings that are typically conducted on a weekly basis during the winter season and bi-weekly during the summer season. These meetings are held more frequently if required. The Company also holds bi-weekly meetings to discuss and determine how UDC is to be managed. Outcomes from these meetings are incorporated into the operational planning meetings.

The operational planning meetings are chaired by the Director of Energy Supply and Policy and include a diverse cross-functional team represented by Gas Supply Planning, Gas Supply Procurement, Gas Costs and Budgets, Gas Control Operations, Gas Storage Operations, Distribution Planning, and Key Customer Contract Management. These meetings determine how the gas supply plan is to be executed and include decisions on gas supply procurement and capacity utilization.

2. Natural Gas Market Context

2.1 2014 Natural Gas Market Review

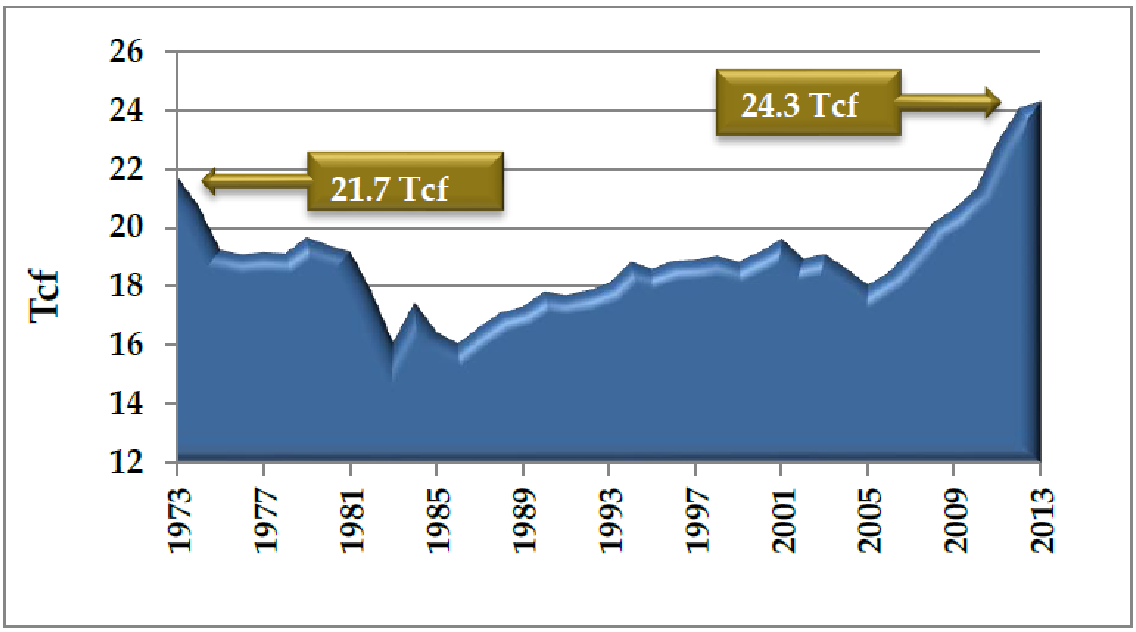
The 2014 Natural Gas Market Review[3] was conducted by the Board during the last quarter of 2014 and into the first quarter of 2015. The review provided a broad perspective of the North American natural gas market and the impacts to Ontario gas markets. The emergence of new natural gas supply basins and the decline of "conventional" natural gas supply basins underpinned discussions on market context.

[3] 2014 Natural Gas Market Review (EB-2014-0289) documentation is located on the Board website at http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/2014%20Natural%20Gas%20Market%20Review%20(EB-2014-0289).

2.2 Emerging Natural Gas Supply

The North American natural gas industry has evolved significantly since technological advances in horizontal drilling and hydraulic fracturing have facilitated the economical extraction of natural gas from shale deposits. Natural gas supply from shale has been the primary driver of United States natural gas production. United States natural gas supply has increased by approximately 30 percent over the last seven years. Recent production has exceeded prior periods of peak production experienced 40 years ago[4] as demonstrated in Figure 5.

Figure 5: United States Natural Gas Production History

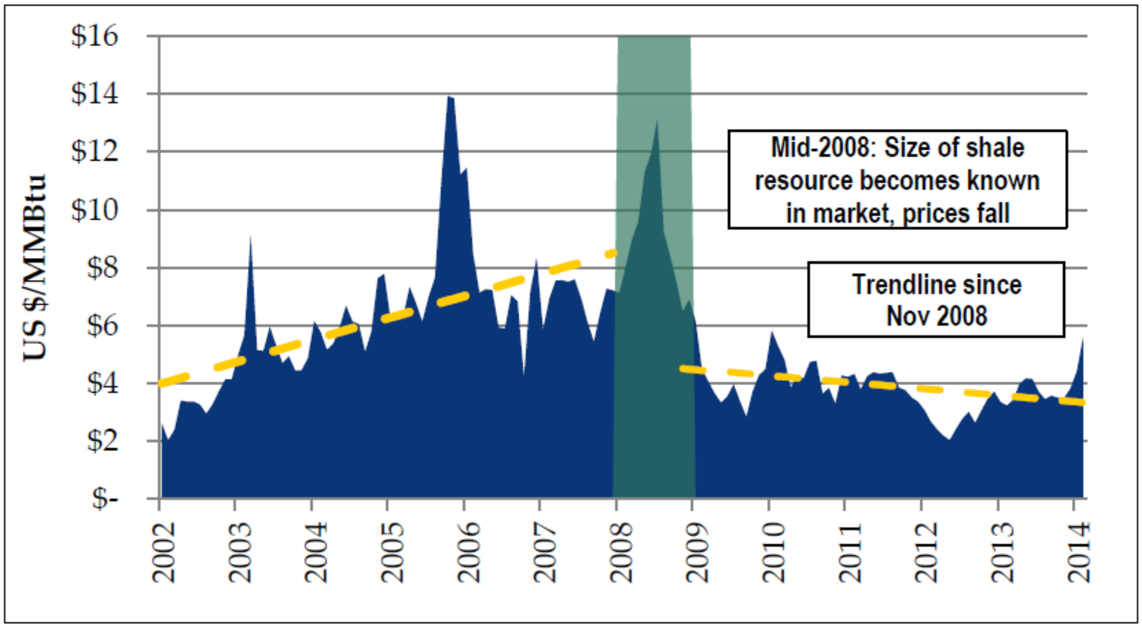


Source: Navigant / U.S. E.I.A.

The increase in natural gas production from shale basins has resulted in declines in natural gas prices. The steep increase in natural gas prices that was experienced at the turn of the century reversed as natural gas production from shale basins expanded. This contributed to a significant decrease in natural gas prices in 2009 and prices have been trending downward since that time as indicated in Figure 6.

[4] EB-2014-0289 2014 Natural Gas Market Review Final Report by Navigant, page 8.

Figure 6 – Henry Hub Price History



Source: Navigant / Platts

The location of shale supply basins has had a significant impact. Historically, gas demand had traditionally been served by a combination of conventional supply basins located in concentrated regions of North America. These supplies were transported via long haul transmission pipelines. The emergence of shale supply basins has changed these traditional pipeline flows. Unlike conventional supply basins, shale supply basins are located all across North America and, as shown in Figure 7, often in close proximity to demand centres. The broad dispersion of shale supply basins has created an opportunity for natural gas supply to be procured closer to demand centers, reducing distance of haul and therefore transportation costs if these supplies can be accessed. This has led to the reconfiguration of the North American natural gas grid and flows. Gas supplies are now flowing in directions opposite to historical flows and existing and new pipelines have been developed to facilitate these flows, particularly in and around shale basins.

Figure 7 - North American Shale Gas Basins

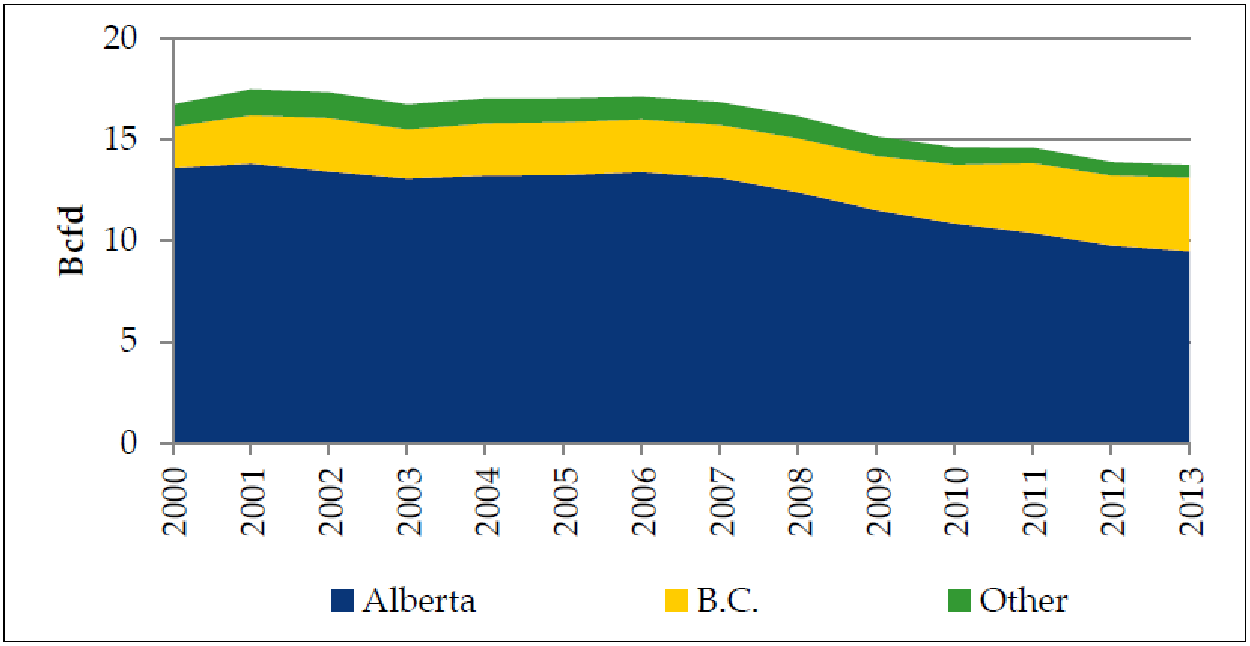
Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

2.3 Western Canadian Sedimentary Basin

Enbridge has traditionally relied on natural gas supply from the WCSB and long haul transportation on the TransCanada Mainline to supply a significant portion of its gas supply plan requirements. At the end of 2000, Enbridge increased portfolio diversity by contracting on Alliance Pipeline and Vector Pipeline which provided additional access to WCSB supply and Chicago supply.

Production in the WCSB peaked in 2001 and has steadily decreased since that time as show in Figure 8. The decline experienced in 2001 was relatively gradual but increased in magnitude around 2007 shortly after the production increases experienced in the United States began.

Figure 8 - Historical Canadian Natural Gas Production



Source: NEB

3. Provincial Regulatory Considerations

3.1 GTA and Parkway Projects

Leave to construct applications were filed with the Board in December 2012 by Enbridge for the GTA Project (EB-2012-0451), by Union Gas in April 2013 for the Brantford-Kirkwall/Parkway D Project (EB-2012-0074), and by Union Gas in July 2013 for the Parkway West Project (EB-2012-0451) (collectively the "GTA and Parkway Projects"). Although the applications were filed separately, the Board combined the proceedings, heard them together, and released a decision granting leave to construct in January 2014.

Collectively, the GTA and Parkway Projects involved the construction of new natural gas pipelines, new compressors, and associated facilities for the purpose of reinforcing the transmission and distribution systems in and around the GTA while providing the GTA with incremental access to transportation capacity from supply hubs such as Dawn and Niagara. The GTA and Parkway Projects also served as an important step in providing similar incremental market access to eastern Ontario, Quebec, and the northeast region of the United States by incorporating 1,200 GJ per day of transmission capacity into Segment A as part of the solution to address transportation capacity restrictions on TransCanada's Mainline in Ontario. Maps that describe the GTA and Parkway Project facilities and locations are located in Appendices 8.1, 8.2, and 8.3.

The GTA and Parkway Projects will provide benefits for Enbridge's gas supply plan and therefore customers. The facilities provide for increased security of supply and market access to supply at Dawn and Niagara Falls. Natural gas markets outside of the GTA will also benefit from the new facilities in conjunction with TransCanada's proposed King's North and related projects.

The GTA and Parkway Projects also result in landed cost benefits due to increased utilization of shorter haul paths and access to emerging supply in the United States.[5]

3.2 Dawn Access Consultative

As a result of the GTA and Parkway Projects, Enbridge is able to provide additional market access to Dawn for its direct purchase customers. Enbridge agreed during the EB-2012-0451 proceeding to consult with customers to create a new transportation service where natural gas supplies could be delivered to Enbridge at Dawn. The consultation was initiated in June 2014 and culminated with the Dawn Access Settlement Agreement which was approved by the Board.

3.3 April and October QRAMs

The level of demand experienced over the winter of 2013/2014 was significantly higher than budgeted. Low storage balances late in the winter season and the need to procure incremental supply from the spot market resulted in significant commodity price adjustments to recover the resulting increase in gas supply costs. The Board confirmed that Enbridge followed its gas supply plan[6] for the 2013/2014 winter, however the level of concern related to the magnitude of the associated QRAM adjustments caused Enbridge to evaluate the risk assumed in its gas supply plan. This evaluation led Enbridge to propose changes to the management of storage balances. These proposed changes were filed in Enbridge's 2015 Rate application in addition to the volume of forecasted demand, actual demand, and supply over this period as summarized in Appendix 8.4 from an excerpt of Exhibit I.D1.EGDI.FRPO.8, Attachment A.

3.4 2015 Rate Adjustment

Enbridge traditionally planned to maintain storage balance targets at levels that would provide maximum storage deliverability until the end of January or beginning of February after which storage balances and subsequently storage deliverability were allowed to decline. For the 2015 gas supply plan, Enbridge proposed to utilize more conservative planning assumptions with respect to the establishment of storage balance targets. The 2015 gas supply plan will maintain full deliverability from storage until the end of February and maintain sufficient storage deliverability throughout March such that a March peak day can be met as late as March 31st. The Board has approved the proposed changes to the management of storage balances for the 2015 rate year.

4. National Regulatory Considerations

4.1 Restructuring Proposal

TransCanada filed its Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013 (RH-001-2011) application with the National Energy Board ("NEB") in September 2011. The application was filed largely in response to the development of new natural gas supply basins, new and

[5] EB-2012-0451 Exhibit J6.X

[6] EB-2014-0191 Decision and Order dated September 25, 2014, page 4.

repurposed transmission pipelines, and generally an increase in competition across North America's natural gas industry as discussed earlier in this memorandum. The NEB captured the essence of this situation in the opening paragraph of their decision where they stated "*[n]o major NEB regulated natural gas transmission pipeline has ever been affected by market forces to the extent that the mainline is now affected*"[7].

The NEB's decision established a new framework for how TransCanada would manage the Mainline going forward. One of the more significant aspects of the decision was the establishment of multi-year fixed tolls over the period of 2013 to 2017. As a result TransCanada was expected to manage the Mainline and through various aspects of the decision such as greater discretion in setting the bid floors for services such as Interruptible Transportation ("IT") and Short Term Firm Transportation ("STFT"). As a result of this change to discretionary pricing Enbridge determined it was not economic to continue to rely on STFT and chose to procure additional long haul FT.

4.2 Energy East and Eastern Mainline Projects

TransCanada's Energy East and Eastern Mainline Projects were filed with the NEB in October 2014 and are currently being review by the NEB. The Energy East Project is a 4,600 KM pipeline project that will transport approximately 1.1 million barrels of crude oil per day from Alberta to eastern Canada. The pipeline will include a combination of newly constructed pipelines and converted natural gas pipelines that are currently part of TransCanada's Mainline. The Eastern Mainline Project includes the construction of a new natural gas pipeline from the City of Markham to the community of Iroquois to replace required natural gas capacity that is being converted to oil service.

The full extent of the impact that these projects will have on Enbridge's gas supply plan will not be known until the Energy East and Eastern Mainline projects are considered by the NEB. But the initial impact of these projects was experienced when TransCanada initiated the March 2013 Existing Capacity Open Season ("May 2013 ECOS") that Enbridge intended to participate in to replace previously contracted STFT capacity. As part of the May 2013 ECOS, TransCanada had reserved all existing long-haul FT capacity into eastern Ontario and Quebec for the Energy East Project resulting in the capacity only being offered as non-renewable FT ("FT-NR"). As a result of no other FT capacity being offered, Enbridge was required to replace previously contracted STFT capacity to the Enbridge EDA with FT-NR capacity that had no renewal rights past November 1, 2017. This created significant concerns over Enbridge's ability to reliably provide natural gas supply for approximately 25% of the peak demand in the Ottawa area.

4.3 Tariff Proposals

TransCanada filed an application to amend the gas transportation tariff for Mainline transportation services in June 2013. The NEB decision on this application resulted in modifications to the renewal provisions that extended the notice period from 6 months to 2 years. This decision increased the planning horizon for securing FT transportation and reduced the flexibility in the gas supply plan to manage shorter term changes in demand.

[7] RH-003-2011 Reasons for Decision, dated March 2013, page 1.

4.4 Abandonment Set Aside and Collection Mechanisms

The NEB initiated the Land Matters Consultative Initiative ("LMCI") in January 2008 for the purpose of ensuring that funds are available when abandonment costs are incurred for all pipelines regulated by the NEB. An Abandonment Surcharge is now applied to all paths on the TransCanada Mainline resulting in increased the landed cost of the gas from the TransCanada system.

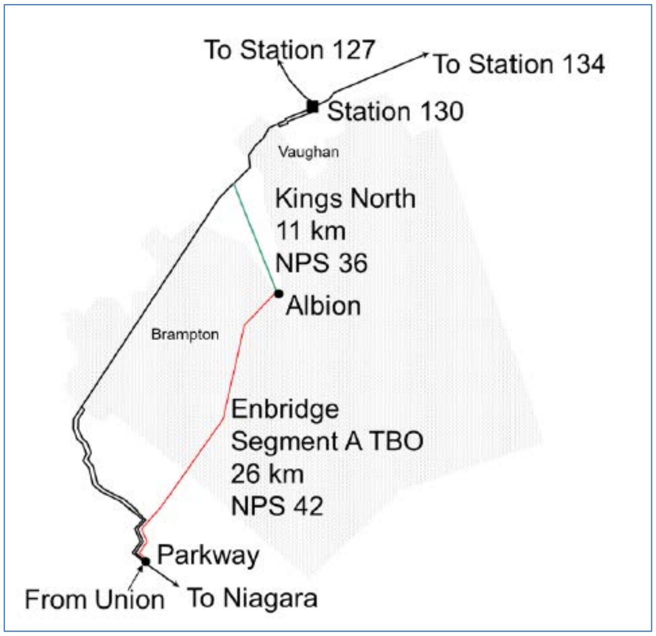
4.5 Mainline 2013-2030 Settlement

In December 2013, TransCanada filed an application for approval of the Mainline 2013-2030 Settlement that was the founded on a negotiated settlement agreement between TransCanada, Enbridge, Gaz Métro Limited Partnership, and Union Gas for the purpose of providing "*market participants with long-term certainty and stability of Mainline tolls, creating an environment that will facilitate the investment required to support the efficient development of natural gas infrastructure in Canada, while providing a reasonable opportunity for Mainline cost recovery*"[8]. The NEB's decision was released in November 2014 which generally approved the application and established a framework for much needed infrastructure development in Ontario.

As a result of the Mainline 2013-2020 Settlement, TransCanada agreed to address the capacity restrictions on the Mainline between Parkway and the Maple compressor station (Station 130) by contracting for transportation by others ("TBO") capacity on Segment A of Enbridge's GTA Project and constructing new infrastructure, for example, The King's North project. The King's North Project is illustrated in Figure 9 and consists of approximately 11 km of new natural gas pipeline that will connect Segment A of Enbridge's GTA project at the Albion station to TransCanada's Mainline near the Maple compressor station. Through coordinated open seasons on the TransCanada Mainline and Union Gas transmission system, market participants now have the opportunity to procure natural gas supply at Dawn for transportation to eastern Ontario, Quebec and the northeast region of the United States.

[8] RH-001-2014 TransCanada Pipeline Limited Application for Approval of Mainline 2013-2030 Settlement, page 1.

Figure 9 – Kings North Project[9]



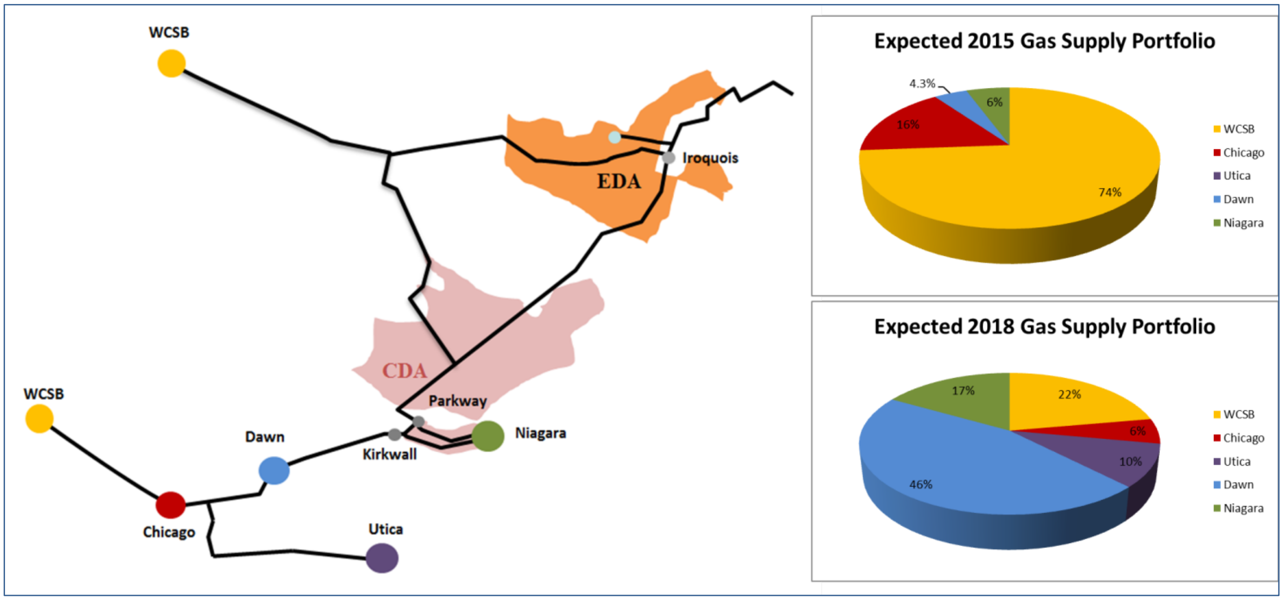
Market access to incremental FT from Dawn addresses the reliability concerns related to the lack of renewal rights inherit with the FT-NR capacity that is currently included in Enbridge's gas supply plan portfolio. Enbridge has executed precedent agreements for incremental transmission capacity on the Union Gas system and the TransCanada Mainline to align with the FT-NR capacity that will expire on November 1, 2017.

The replacement of FT-NR capacity with FT capacity from Dawn is a critical improvement to the reliability of Enbridge's gas supply plan. The open seasons offered by TransCanada and Union Gas for the incremental FT capacity required a 15 year term commitment. The 15 year term will be managed through flexibility provided by shorter term contracts already contained within Enbridge's supply portfolio.

The incremental market access to Dawn enhances the diversity of gas supply and transportation in the gas supply plan. As a result of the open seasons for new capacity that have been offered by TransCanada and Union Gas as a result of the Mainline 2015-2030 Settlement, Enbridge is expecting to more evenly distribute the amount of supply that is procured from various supply hubs across North America as shown in Figure 10. This diversity reduces significant reliance on any one supply basin, increases reliability and lowers the landed cost of gas supply into the franchise. This is accomplished by replacing more expensive long haul transportation with short haul transportation as discussed earlier in the GTA and Parkway Projects section of this memorandum.

[9] TransCanada King's North Connection Pipeline Project application dated August 2014, Page 3-9

Figure 10 – Supply Portfolio Diversification



5. 2015 Gas Supply Plan

5.1 Peak Day Coverage

A discussion on peak day coverage was provided in EB-2014-0276, Exhibit D1, Tab 2, Schedule 1 as part of the annual rate application and an excerpt is included below. The breakdown of the peak day requirement and supply forecast from EB-2014-0276, Exhibit D1, Tab 2, Schedule 6 is provided in Appendix 8.5.

> *In EB-2011-0354 Enbridge presented a new Design Criteria Study which all parties agreed to accept on a phased in approach. The Design Day Criteria is based upon a 1 in 5 recurrence interval. The new Design Criteria Study was filed inEB-2011-0354 at Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2015 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak. Enbridge is currently forecasting a design peak day level of 105 534 103m3 (3.7 Bcf) during the winter season of the 2015 Test Year.*
>
> *The Company has chosen to maintain the same level of Peaking Services for 2015 as was forecast for 2014. Also, similar to 2014 the Company chose to rely principally on TCPL FT service to meet the 2015 Peak Day Demand. The driver for this decision is based upon events at the National Energy Board ("NEB"). On March 27, 2013 the NEB issued its decision in TransCanada Compliance filing RH-003-2011. As discussed as part of the Settlement Agreement in EB-2012-0459 at Exhibit N1, Tab 2, Schedule 1, the ability for TCPL to charge for STFT service an amount in excess of the FT toll made contracting for STFT service inappropriate. TCPL is currently offering STFT service for the November 2014 to March 2015 period at a minimum bid floor of 1,200% of the current FT toll for each month.*

The Company intends to continue to monitor the availability of transport to the franchise area and to look for alternatives that will provide value to the customers of Enbridge while still providing safe and reliable service. If alternatives are found then any differences in the cost of those services versus those forecasted as part of the 2015 gas costs will be captured in the 2015 PGVA.

The Company's plan for meeting its peak day requirements in 2015 includes an increase in TCPL FT capacity of approximately 150,000 GJ/day driven primarily by four factors compared to 2014: 1) an increase in the overall peak day demand due to growth, 2) a decline in the level of interruptible volume largely stemming from a decline in the number of interruptible customers, 3) the migration of Ontario T-Service ("OTS") customers to either System Sales or Western T-Service ("WTS"), and 4) a decrease in available delivered service supplies. Prior to renewal of their contracts with Enbridge a number of interruptible customers including institutional customers such as schools and hospitals indicated that the curtailment costs they experienced this past winter were excessive and requested to move from an Interruptible ("IT") Rate to a Firm Rate. The Company evaluated the requests on a case by case basis and once it was determined that a switch from IT to Firm would not impact the distribution system, customers were allowed to move to a Firm Rate. As a consequence, the Company had to look for additional supplies to meet its peak day requirements. OTS customers are required, under their direct purchase agreement, to deliver a daily volume directly into the franchise area. The migration of customers from OTS to either System Sales or to WTS results in less volume being delivered directly into the franchise area by Direct Purchase customers. As a consequence, the Company had to look for additional supplies to meet its peak day requirements. A breakdown of the peak day requirement and supply forecast is shown at Exhibit D1, Tab 2, Schedule 6.

Similar to 2014, the incremental capacity required to meet forecasted 2015 peak day demand will not be utilized at a 100% load factor based upon the 2015 volumetric forecast. The Company is forecasting $166.4 million in cost consequences associated with unutilized transportation capacity. This forecast is also based upon the TCPL tolls in place at the time of the derivation of the October 2014 QRAM. As part of the Settlement Agreement in EB-2012-0459 parties agreed that, instead of including a forecasted Unabsorbed Demand Charge ("UDC") amount in gas costs for rate making purposes, any actual UDC costs incurred during the year would be captured in either the 2014 DDCTDA or the 2014 UDCDA. The Company is proposing a similar treatment be used in 2015 with one minor exception. The Company believes that any costs associated with actual UDC costs can be tracked through a single deferral account and is therefore proposing the 2015 Unabsorbed Demand Charges Deferral Account ("2015 UDCDA"). In 2015 Enbridge will use best efforts to mitigate UDC that would otherwise be recorded in the 2015 UDCDA. For example, during the summer months when the Utility is injecting gas into storage, whenever possible, the Company will use transportation capacity to displace discretionary purchases of gas at Dawn. If there still remains unutilized capacity the Company will use best efforts to make that capacity available to third parties to mitigate the UDC costs. Similar to 2014 the Company intends to *continue to provide monthly reporting of the on-going amounts in the 2015 UDCDA. The Company has provided at Appendix A, a monthly breakdown of the forecasted 2015 UDCDA.*

5.2 Transportation

A discussion on the transportation assets that were included in the 2015 Gas Supply Plan was discussed in EB-2014-0276, Exhibit D1, Tab 2, Schedule 1 as part of the annual rate filing and an excerpt is included below. The list of transportation contracts from EB-2014-0276, Exhibit D1, Tab 2, Schedule 2 is provided in Appendix 8.6.

Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the 2015 Test Year. These include service entitlements with TransCanada (both long haul and short haul), Alliance Pipeline and Vector Pipeline. For purposes of this forecast, contracts were priced based upon current tolls and if contracts had an expiry date during the Test Year these contacts were assumed to expire. For instance, the Company has chosen not to renew its contract with Alliance Pipeline as well as two Vector Pipeline contracts totaling 100 000 MMBTU/d. These contracts expire on November 30,, 2015 and October 31,, 2015 for each pipeline respectively. Included in the forecasted supply portfolio effective November 1, 2015 is the acquisition of 200 000 GJ/day of supply at the Niagara interconnect on TCPL. In order to transport that gas from the Niagara import point, the Company has assumed the acquisition of 200 000 GJ/day of Niagara Falls to Enbridge Parkway CDA capacity on TCPL.

For the purposes of the 2015 forecast the Company has assumed the assignment of 31,098 Gj/day of TCPL short haul capacity to Direct Purchase customers effective November 1, 2014 to October 31, 2015.

With the forecasted in service date of November 1, 2015 for the GTA Project, the Company is assuming a number of changes in its plan to meet its peak day demand. A number of TCPL FT contracts will be allowed to expire, the Company will no longer rely on peaking service in the CDA and Direct Purchase customers will be allowed to shift their deliveries to Dawn, as proposed in the Dawn Access Settlement Agreement recently approved by the Board (EB-2014-0323). Phase 1 will consist of an assignment of up to 149,818 GJ/day of TCPL Dawn to CDA short haul capacity). Replacing these, the Company will increase its reliance on M12 service entitlements with Union Gas.

M12 service entitlements on the Union system currently total 2,225,102 GJ/day (2,081 MMcf/day) and for the purposes of the 2015 gas cost budget are forecast to increase by 400,000 GJ/day (375 Mmcf/day) commensurate with the in-service date of the GTA Project. M12 provides for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The *gas cost forecast assumed January 1, 2014 Union tolls. A list of the Company's transportation contracts can be found at Exhibit D1, Tab 2, Schedule 2.*

5.3 Storage

A discussion on the storage assets that were included in the 2015 Gas Supply Plan was discussed in EB-2014-0276, Exhibit D1, Tab 2, Schedule 1 as part of the annual rate filing and an excerpt is included below.

The Company has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region. Tecumseh is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility.

The Company also has contracted capacity with third party providers that are valued at market based pricing. The size of the contracted capacity and the term of the contracts vary such that every year Enbridge will enter the market place via an RFP process seeking to replace the contracted capacity scheduled to expire March 31 of that year. For purposes of the 2015 gas cost forecast the Company has assumed the amount and value of storage set to be extended. Any variation between this assumed cost and the actual cost of storage acquired through an RFP process will be captured in the 2015 Storage & Transportation Deferral Account (2015 S&TDA).

In the April 2014 and October 2014 QRAM proceedings (EB-2014-0039 and EB-2014-0191 respectively) the Company discussed its utilization of storage as a part of its gas supply plan. Historically the Company would establish storage targets to maintain sufficient deliverability from storage and would maintain maximum deliverability until late January to early February in order to meet design day or near design demand requirements. As demand declined so too would storage deliverability throughout the winter. To offset the decline in deliverability, the Company would purchase additional delivered supplies if demand was above budget. Developing a gas supply plan in this fashion proved satisfactory during periods of budgeted or slightly colder than budget winters. This was not the case in the winter of 2014 and the Company was forced to purchase significantly higher volumes of gas at Dawn to serve the needs of its customers.

For purposes of preparing the 2015 gas supply plan the Company has implemented a change with respect to how it plans to manage its storage balances. The Company is forecasting storage targets such that maximum deliverability from storage can be maintained until the end of February and such that deliverability from storage is sufficient to meet March peak day as late as March 31. An advantage of maintaining higher storage balances until the end of February is that in the event of colder than budgeted demand in the month of March the Company can reduce the requirement of daily spot purchases at presumably higher prices.

Also during the April 2014 and October 2014 QRAM proceedings the Company explained its long term practice of the use of a seven day ahead forecast of degree days along with budgeted weather beyond seven days to make gas procurement decisions. The Company plans to make a change in how it uses forecasted weather to make procurement decisions next winter. The Company will continue to rely on a seven day ahead forecast of degree days as part of its *decision making process for gas procurement for the upcoming week. The Company, however, intends to look to medium term weather forecasts as a means of assessing medium term demand impacts in order to help decide whether or not it should adjust its supply plan for the upcoming month or the remainder of the winter season. The Company currently tracks several medium term weather forecasts and will look to some consensus of these forecasts as another indicator of future demand. Depending on a number of factors (such as the point in the winter when the decision is being made, where storage balances are relative to target, what is happening in the markets where the Company purchases gas) the Company may choose to adjust its month ahead and/or seasonal purchases taking into consideration not only budgeted weather but also medium term weather forecasts. The cost consequences of such decisions will be reflected within the PGVA.*

Maintaining higher storage balances later into the winter season in conjunction with using a medium term weather forecast (as described above) will allow the Company to react sooner and more effectively to make adjustments to the supply plan to meet changing demand. By reacting sooner it will provide for an ability to acquire month ahead supplies to help reduce daily spot purchases. Conversely in a warmer than normal year the longer term forecast will allow for the potential to reduce purchases sooner.

6. Future Natural Gas Transportation Considerations

6.1 2016 Open Seasons

In November 2013, TransCanada conducted a New Capacity Open Season for firm transportation effective November 1, 2016 ("2016 NCOS") including receipts from Union Parkway Belt for delivery to eastern Ontario, Quebec, and the northeast region of the United States. The 2016 NCOS was premised on NEB approval of the Mainline 2013-2030 Settlement Agreement. Union Gas coordinated an open season on their transmission system with the 2016 NCOS. Together, these open seasons provided market access to incremental transmission capacity from supply hubs such as Dawn and Niagara.

Market access to Dawn provided much needed relief to the lack of firm transportation capacity required by markets in eastern Ontario, Quebec, and the northeast region of the United States resulting from capacity restrictions on the TransCanada Mainline and the expectation of the need to replace FT-NR stemming from the development of Energy East Project. The open seasons were of particular importance to Enbridge's gas supply plan which currently includes 166,000 GJ per day of FT-NR capacity that will expire on November 1, 2017 with no option to be renewed. Enbridge has executed precedent agreements with Union Gas for replacement capacity from Dawn to Parkway and an equivalent amount with TransCanada from Union Parkway Belt to Enbridge EDA effective November 1, 2017.

6.2 2017 Open Seasons

In December 2014, TransCanada conducted a New Capacity Open Season for firm transportation effective November 1, 2017 ("2017 NCOS"). Similar to the 2016 NCOS, the 2017 NCOS was premised on the 2013-2030 Settlement Agreement but since the NEB had released its Letter Decision dated

November 29, 2014, the 2017 NCOS was subject to being withdrawn subject to Acceptable Approval of the parties to the Mainline 2013-2030 Settlement Agreement. In conjunction with the 2017 NCOS, Union Gas conducted an open season on their transmission system.

Enbridge has executed precedent agreements with TransCanada on two paths which include Union Parkway Belt to Enbridge CDA and Union Parkway Belt to Enbridge EDA. The natural gas supply for both of these paths will be provided from Dawn through existing and new transportation capacity as part of the Union Gas open season.

The new firm transportation capacity has been requested by Enbridge to facilitate:

1. New services for in-franchise customers;
2. Replacement of peaking supplies;
3. To address medium term demand growth; and
4. Gas supply portfolio improvements.

<u>New services for in-franchise customers</u>

Enbridge has received elections from the majority of its direct purchase customers requesting to migrate from their current transportation services to the new DTS that resulted from the Dawn Access Settlement. The new transportation capacity requested by Enbridge in the 2017 NCOS, including the conversion of long haul capacity for direct purchase customers who are currently delivering to Empress, will be used to provide the level of service that has been requested under phase 2 of the DTS election process. In addition to requiring the transportation capacity to support the new DTS, Enbridge has experienced a decline in the contracted capacity for interruptible distribution services that are used to manage periods of high demand. A portion of the transportation capacity requested in the 2017 NCOS will be used to offset customer migration from interruptible distribution services and ensure the distribution system demand will continue to be met in a safe, reliable, and cost effective manner.

<u>Replacement of peaking supply</u>

Enbridge has historically relied on peaking services to meet its peak day and near peak requirements in the Ottawa area. This is an on demand short term service provided by third parties who typically divert supply destined for export markets. Similar to concerns related to the interruptible service, TransCanada's plans to reduce transportation capacity in the region as a result of the Energy East Project will reduce these exports and therefore the availability and reliability of these peaking services. As a result, Enbridge is no longer comfortable relying on peaking service and will replace it with the firm transportation that has been requested in the 2017 NCOS.

Medium term demand growth

Enbridge requires incremental upstream transportation to accommodate growth in peak day demand.

Gas supply portfolio improvements

The Enbridge gas supply plan is based on balancing the principles of reliability, diversity, cost and flexibility. The gas transportation services that have been acquired and requested will improve the reliability and diversity of Enbridge's gas supply portfolio while reducing the landed cost of natural gas in the franchise through increased access to Marcellus and Utica shale supply basins through Dawn. This will be achieved in part through net new supply requirements as discussed above and by converting existing long-haul transportation contracts in a manner that is consistent with the 265 TJ per day long-haul commitment that was made as part of the Mainline Settlement Agreement that was originally executed on October 31, 2013.

7. Future Provincial Regulatory Considerations

7.1 Review of Board's Policy on Gas Procurement and Gas Supply Plans

On March 31, 2015, the Board published a Staff Report to the Board regarding the 2014 Natural Gas Market Review (the "Staff Report"). Included in the Staff Report was a recommendation for the Board to initiate a proceeding that will "examine the Board's policy in relation to gas procurement and the assessment and approval of distributor gas supply plans"[10] which the Board indicated would be conducted through a stakeholder consultation. Information related to the scope, activities, and schedule for this proceeding will be provided at a later date, and at that time Enbridge will assess what impacts that the outcomes of the proceeding will have on its gas supply planning process.

7.2 Incremental Storage

As discusses earlier in this memorandum, Enbridge has incorporated changes in how is manages storage deliverability targets in its 2015 gas supply plan through an increase in forecasted natural gas supply purchases in the winter period and a subsequent decrease in forecasted natural gas supply purchases later in the year. The shifting of supply purchases in this manner reduces forecast storage withdrawals early in the winter thereby maintaining higher forecast storage inventory, and subsequently higher storage deliverability, later into the winter season.

Enbridge expects to manage storage deliverability targets in a similar manner for the 2016 gas supply plan. Looking beyond the 2016 gas supply plan, Enbridge anticipates that other changes , such as incorporating incremental or contingency storage in the gas supply plan, could be used to manage the storage deliverability targets in a more effective manner. Preliminary analysis indicates that 16 Bcf of incremental storage would be required to maintain a similar level of risk assumed in the peak day demand forecasting. A summary of the preliminary analysis is included in Figure 11.

[10] Staff Report to the Board on the 2014 Natural Gas Market Review (EB-2014-0289) dated March 31, 2015, page 29.

Figure 11 – Incremental Storage Analysis Summary

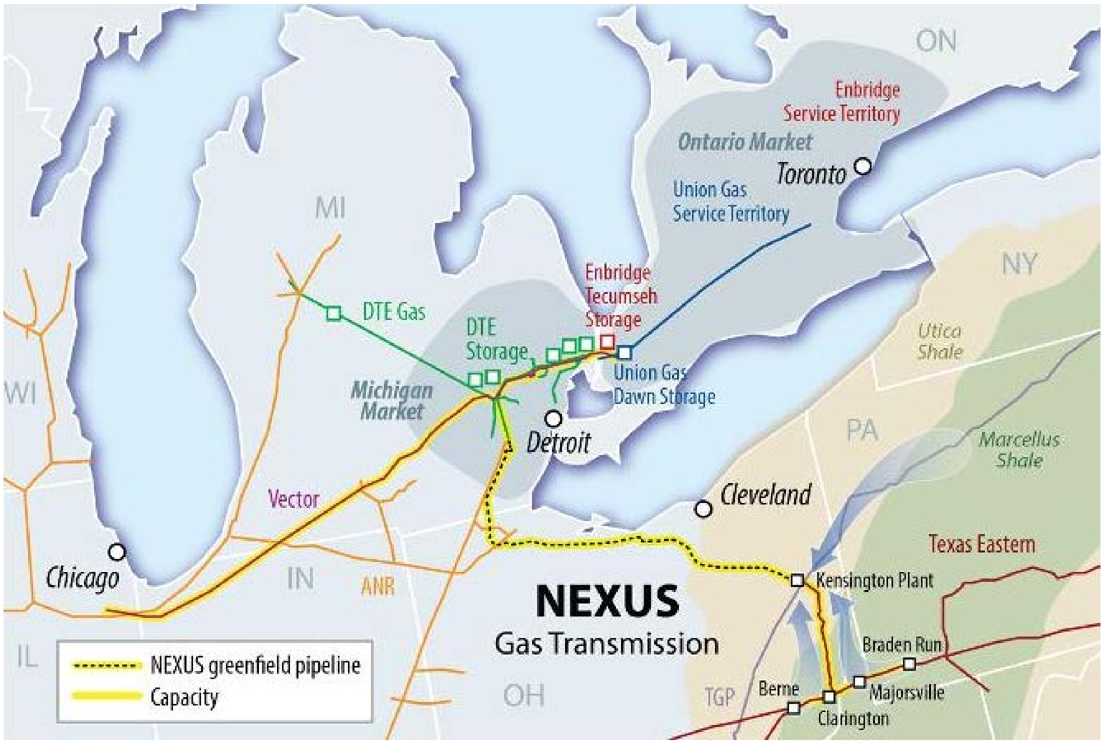
Incremental Storage Requirements*: Various Design Criteria (Normal Distribution)			
Design Criteria Recurrence Interval	Associated Probability of Being ≥	Central Weather Zone Winter HDD	Incremental Storage Requirement (Bcf)
Current 1 in 2	50%	2,945	-
1 in 5	20%	3,207	9
1 in 10	10%	3,303	14
1 in 15	≈6%	3,364	16
Peak Day Equivalent	5.7%	3,369	16
1 in 20	5%	3,384	21
* Analysis based on 2015 budget			

Enbridge is investigating how to move forward with a more thorough analysis of storage requirements and the cost and risk trade-offs associated with more storage capacity. When it has completed a more thorough analysis, Enbridge will consider when and how to bring forward the resulting recommendations to the Board and stakeholders.

7.3 Pre-approval of NEXUS costs

The NEXUS Gas Transmission Project ("NEXUS") is a proposed natural gas transmission pipeline that will deliver up to 1.5 Bcf per day of supply from the Appalachian Basin, which includes Marcellus and Utica shale gas production, to the DTE Energy Company system or the Vector Pipeline for delivery to Dawn. A map of NEXUS is included in Figure 12.

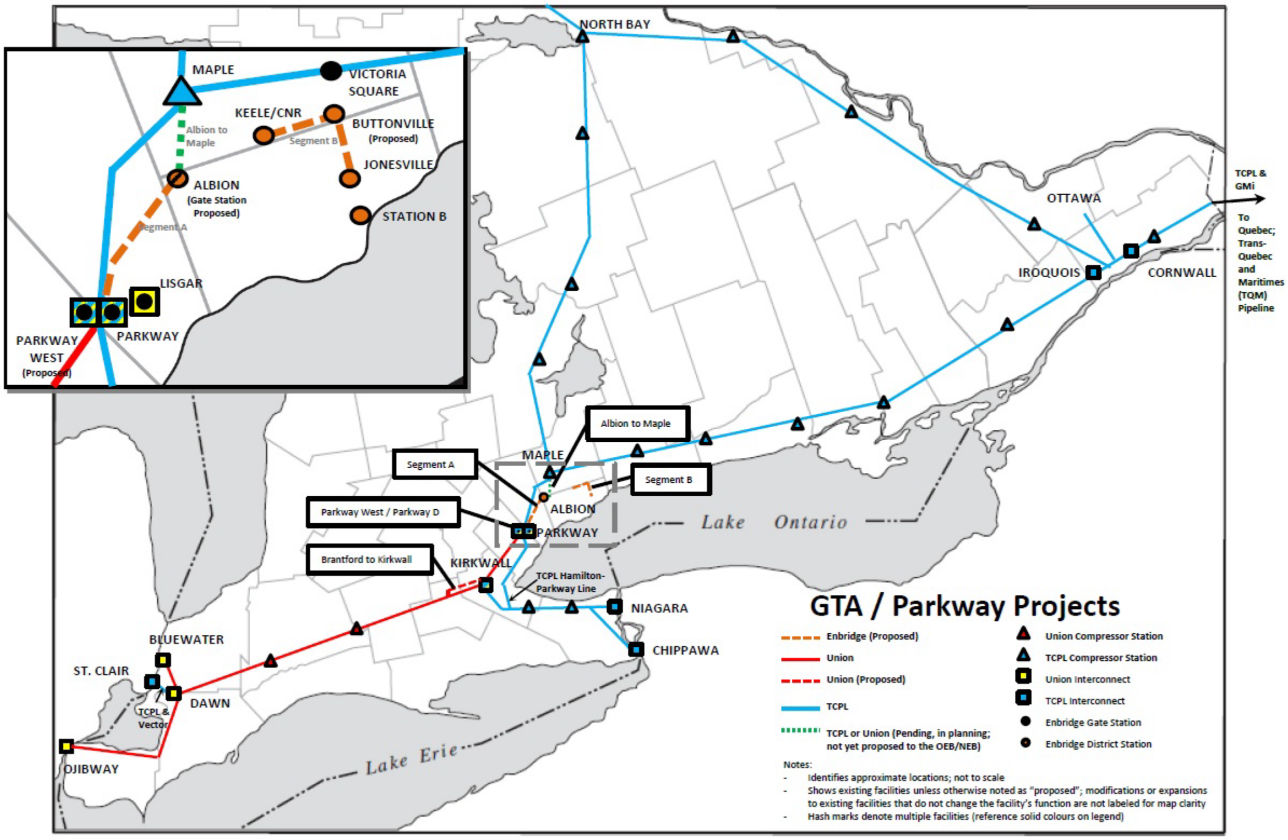
Figure 12 – NEXUS Gas Transmission



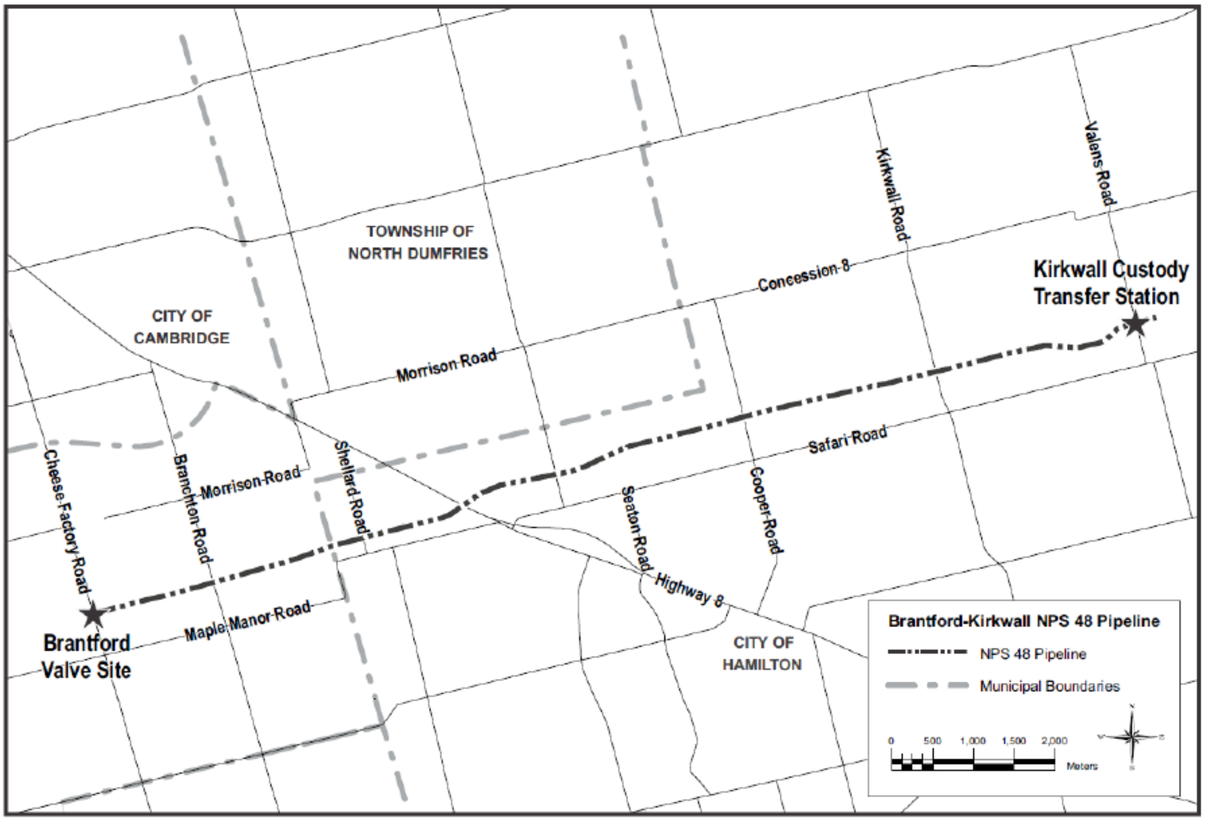
Enbridge signed a precedent agreement with NEXUS for 110,000 Dth per day for firm transportation service commencing on November 1, 2017 to diversify its gas supply plan portfolio while improving the reliability of supplies being transported to Dawn at a competitive landed cost. The precedent agreement is conditional on gaining Board pre-approval of the associated contract costs. Enbridge is expecting to file an application with the Board for pre-approval in the second quarter of 2015.

8. Appendices

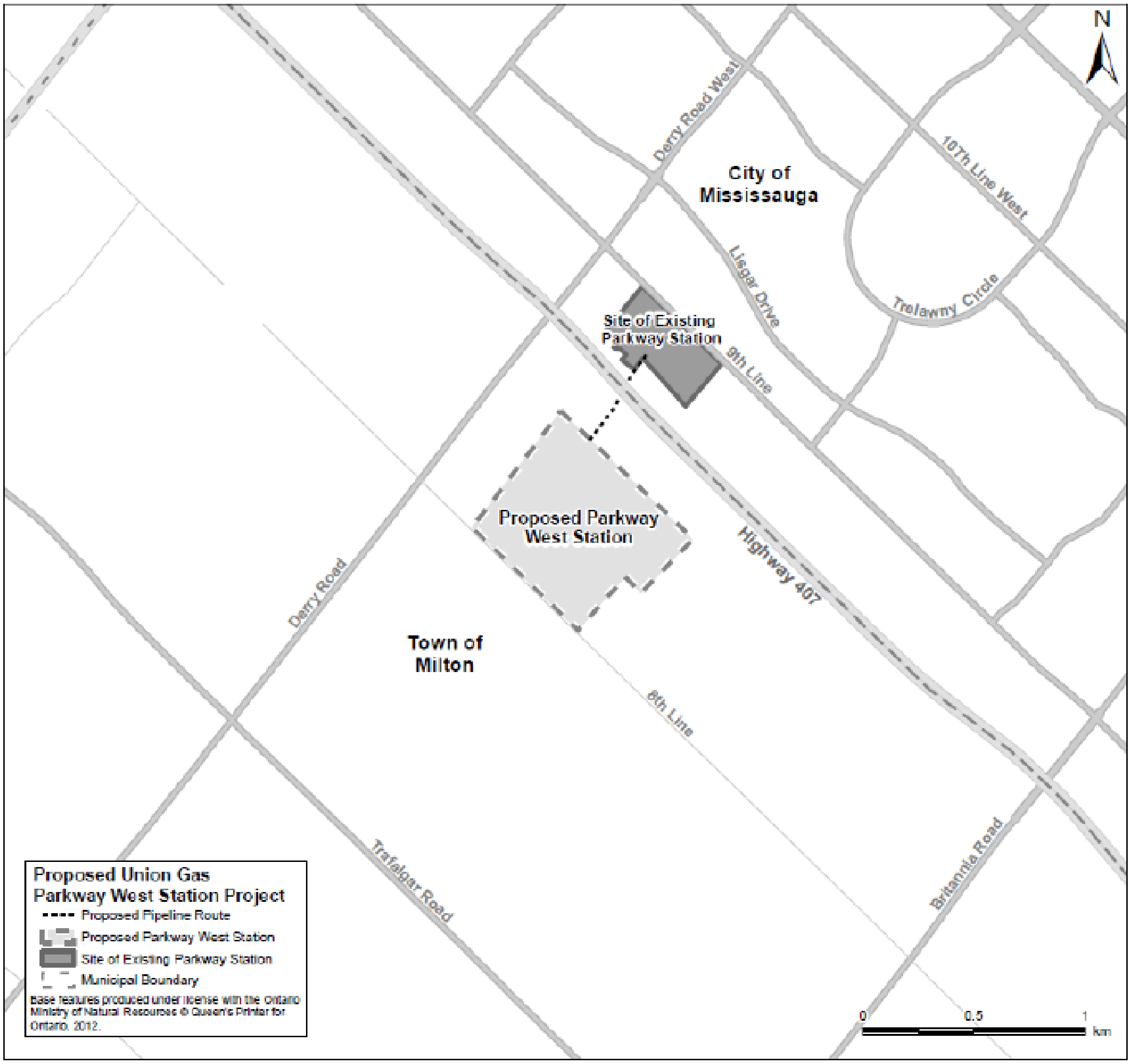
8.1 GTA Project Map



8.2 Brantford-Kirkwall/Parkway D Project



8.3 Parkway West Project Map



8.4 2013/2014 Forecasted and Actual Demand

2013 Actual Column 1 November	Column 2 December	Item #	PJ's	2014 Column 3 January	Column 4 February	Column 5 March	Column 6 April	Column 7 May	Column 8 June	Column 9 July	Column 10 August	Column 11 September	Column 12 October	Column 13 November	Column 14 December	Column 15
43.7	62.0	1.	Forecasted Demand	69.7	60.7	53.5	33.2	20.8	14.7	13.4	13.3	15.0	27.2	41.5	60.4	423.3
51.1	70.3		Actual Demand	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.3	27.1	51.7	61.9	495.1
			Supply													
19.3	19.9	2.	EGD Contracted Long Haul TCPL Capacity	19.5	17.6	19.2	18.9	19.8	18.9	19.5	19.6	18.9	19.5	19.1	19.7	230.1
-	-	3.	Less Unutilized Capacity	-	-	-	-	-	-	(3.1)	(6.7)	(5.2)	(5.1)	-	-	(20.1)
19.3	19.9			19.5	17.6	19.2	18.9	19.8	18.9	16.4	12.9	13.7	14.4	19.1	19.7	210.0
9.1	9.3	4.	Direct Purchase Own Transportation	9.9	8.7	9.5	9.4	10.9	10.5	10.6	10.5	9.9	9.6	8.3	8.6	116.3
8.7	8.9	5.	Alliance/Vector	8.8	8.1	10.2	8.6	9.0	8.6	6.9	6.2	6.0	6.3	7.7	9.0	95.4
2.1	11.4	6.	Dawn Discretionary	15.0	16.2	21.8	10.0	-	-	-	-	-	0.0	5.1	13.6	81.6
-	-	7.	Peaking Supplies	1.6	0.1	0.6	-	-	-	-	-	-	-	-	-	2.3
39.2	49.5		Total Supply	54.7	50.6	61.3	46.9	39.6	38.0	33.9	29.5	29.6	30.3	40.2	50.9	505.7
12.0	20.8	8.	Storage Requirement	31.2	22.5	9.2	(6.0)	(17.5)	(22.6)	(18.5)	(14.9)	(13.3)	(3.2)	11.4	11.0	(10.6)
51.2	70.3		Total Supply	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.3	27.1	51.7	61.9	495.1

8.5 2015 Budget Peak Day Demand

Item #	2014 Budget Peak Day Demand GJ's	Column 1 CDA	Column 2 EDA	Column 3 Total	2015 Budget Peak Day Demand GJ's	Column 4 CDA	Column 5 EDA	Column 6 Total
1.	Demand	3,288,088	673,262	3,961,350	Demand	3,303,548	674,042	3,977,590
2.	Less Curtailment	(133,995)	(28,705)	(162,700)	Less Curtailment	(83,874)	(33,259)	(117,133)
3.	Net Peak Day Demand	3,154,093	644,557	3,798,650	Net Peak Day Demand	3,219,674	640,783	3,860,457
4.	TCPL FT Capacity	271,468	370,627	642,095	TCPL FT Capacity	404,538	390,627	795,165
5.	TCPL STFT	-	-	-	TCPL STFT	-	-	-
6.	TCPL Short Haul	151,818	114,000	265,818	TCPL Short Haul	158,720	114,000	272,720
7.	TCPL STS	369,464	80,611	450,075	TCPL STS	369,465	80,611	450,076
8.	Ontario T-Service	300,354	26,576	326,930	Ontario T-Service	243,353	5,718	249,071
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	182,738	-	182,738	Delivered Service	167,739	-	167,739
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,506	52,754	158,260
12.	Total Supply	3,156,374	644,567	3,800,941	Total Supply	3,224,348	643,710	3,868,058
13.	Sufficency/(Deficiency)	2,281	10	2,291	Sufficency/(Deficiency)	4,674	2,927	7,601

Filed: 2014-11-28
EB-2014-0276
Exhibit D1
Tab 2
Schedule 6
Page 1 of 1

8.6 Transportation Contract Summary

Filed: 2014-11-28
EB-2014-0276
Exhibit D1
Tab 2
Schedule 2
Page 1 of 1

STATUS OF TRANSPORTATION CONTRACTS

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Monthly Demand Charge		Estimated Commodity Charge		Expiry Date
	Current Contracts									
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-17
2	TCPL FT - CDA	Empress to CDA	201,070	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-15 [1]
3	TCPL FT - CDA	Empress to CDA	9,000	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Oct-15
4	TCPL FT - CDA	Empress to CDA	56,000	GJ	varies	47.62803	$/GJ	-	$/GJ	31-Dec-15
5	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-17
6	TCPL FT - EDA	Empress to EDA	50,000	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Mar-15
7	TCPL FT - EDA	Empress to EDA	116,250	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-15
8	TCPL FT - EDA	Empress to EDA	166,000	GJ	varies	49.13597	$/GJ	-	$/GJ	31-Oct-16 [2]
9	TCPL FT - Iroquois	Empress to Iroquois	26,956	GJ	varies	49.45575	$/GJ	-	$/GJ	31-Oct-17
10	TCPL FT Dawn to CDA		149,818	GJ	varies	7.16453	$/GJ	0.01360	$/GJ	31-Oct-17 [3]
11	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(31,098)	GJ	varies	7.16453	$/GJ	0.01360	$/GJ	31-Oct-16 [3]
12	TCPL FT Dawn to EDA		114,000	GJ	varies	13.28433	$/GJ	0.03229	$/GJ	31-Oct-17
13	TCPL FT Dawn to Iroquois		40,000	GJ	varies	12.76919	$/GJ	0.03038	$/GJ	31-Mar-16
14	TCPL FT Parkway to CDA		572	GJ	varies	3.14523	$/GJ	0.00350	$/GJ	31-Oct-17
15	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.17490	$/GJ	0.00326	$/GJ	31-Oct-18
16	TCPL STS Parkway to CDA		283,892	GJ	varies	1.69730	$/GJ	0.00024	$/GJ	31-Oct-17
17	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-17
18	TCPL STS Parkway to EDA		9,716	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-17
19	Niagara to CDA		200,000	GJ	N/A					
20	Nova Transmission	AECO to Empress	166,869	GJ	N/A	5.35000	$/GJ	-	$/GJ	31-Oct-16
21	Nova Transmission	AECO to Empress	20,000	GJ	N/A	5.35000	$/GJ	-	$/GJ	31-Oct-15
22	Alliance Pipeline	Alberta to US border	2,124.6	10^3m^3	varies	981.1600	$\$/10^3m^3$	-	$\$/10^3m^3$	30-Nov-15 [4]
23		US border to Chicago	75.0	mmcf	varies	16.5000	$US/dth	-	$US/dth	30-Nov-15
24	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	-	$US/dth	30-Nov-17
25		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	-	$/GJ	30-Nov-17
26	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	-	$US/dth	30-Nov-17
27		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	-	$/GJ	30-Nov-17
28	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies	Negotiated Toll				30-Nov-15 [5]
29		Cdn border to Dawn	52,753	GJ	varies	Negotiated Toll				30-Nov-15 [5]
30	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies	Negotiated Toll				30-Nov-15 [5]
31		Cdn border to Dawn	52,753	GJ	varies	Negotiated Toll				30-Nov-15 [5]
32	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Mar-14 [6]
33	Union Gas Dawn to Parkway		106,000	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-18
34	Union Gas Dawn to Parkway		57,100	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-19
35	Union Gas Dawn to Parkway		18,703	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
36	Union Gas Dawn to Parkway		200,000	GJ	varies	2.9610	$/GJ	-	$/GJ	31-Oct-22
37	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
38	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Oct-14
39	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Mar-14
40	Union Gas Parkway to Dawn		236,586	GJ	varies	0.5790	$/GJ	-	$/GJ	31-Mar-14

notes:
(1) in the event of a delay in the GTA project these contracts continue beyond October 31, 2015
(2) Contract Effective November 1, 2015
(3) In addition to the toll provided above there is a monthly surcharge as well - $0.13281/GJ/month
(4) the Alliance contract will not be renewed beyond the November 30, 2015 expiry date
(5) these Vector contracts will not be renewed beyond the November 30, 2015 expiry date
(6) the Company is planning to contract for an incremental 400,000 GJ/day of M12 capacity effective November 1, 2015
(7) volume increases to 75,000 in second year of contract

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Monthly Demand Charge		Estimated Commodity Charge		Effective Date	Expiry Date
	Pending Contracts to meet Peak Day in 2015										
41	Peaking Service - CDA		105,505			varies		varies		1-Dec-14	31-Mar-15
42	Peaking Service - EDA		52,753			varies		varies		1-Dec-14	31-Mar-15
			158,258								
43	TCPL FT - CDA	Empress to CDA	75,000	GJ	varies	47.62803	$/GJ	-	$/GJ	1-Jan-15	31-Oct-18
44	Nova Transmission	AECO to Empress	75,000	GJ	N/A	5.35000	$/GJ	-	$/GJ	1-Jan-15	31-Dec-15
45	Niagara to CDA		25,000			Negotiated Toll				1-Nov-13	31-Mar-15
46	Niagara to CDA		60,000			Negotiated Toll				1-Nov-14	1-Mar-16 [7]
47	Dawn to CDA		25,000			Negotiated Toll				1-Nov-13	31-Mar-15
48	Dawn to CDA		25,000			Negotiated Toll				1-Nov-14	1-Mar-16

Witness: D. Small

2014 RRR FILINGS – SERVICE QUALITY INDICATORS

1. Please find the Service Quality Indicator results in the tables below.

G.2.1.9.A - TELEPHONE ANSWERING PERFORMANCE

G.2.1.9.A.1 - Call Answering Service Level (CASL)
Measure Calculations: CASL = Number of calls reaching a distributor's general inquiry number answered within 30 seconds divided by the number of calls received by a distributor's general inquiry number.
OEB Approved Standard: Yearly performance shall be 75% with minimum monthly standard of 40%.

Month	Number of Calls Reaching a Distributor's General Inquiry Number Answered Within 30 Seconds (1)	Number of Calls Received by a Distributor's General Inquiry Number (2)	Call Answer Service Level (%) (3=1/2*100)
Jan.	179,159	222,705	80.4%
Feb.	156,190	194,230	80.4%
Mar.	190,747	239,620	79.6%
Apr.	195,010	242,258	80.5%
May	192,831	245,660	78.5%
Jun.	173,205	224,037	77.3%
Jul.	185,037	238,122	77.7%
Aug.	167,091	217,879	76.7%
Sept.	185,131	237,936	77.8%
Oct.	187,304	245,814	76.2%
Nov.	188,598	233,095	80.9%
Dec.	170,689	206,359	82.7%
TOTAL	2,170,992	2,747,715	79.0%

Witnesses: K. Lakatos-Hayward
L. Parrington

G.2.1.9.A.2 - Abandon Rate (AR)
Measure Calculations: AR = Number of calls abandoned while waiting for a live agent divided by a total number of calls requesting to speak to a live agent.
OEB Approved Standard: Performance shall not exceed 10% on a yearly basis.

Month	Number of Calls Abandoned While Waiting for a Live Agent (1)	Total Number of Calls Requesting to Speak to a Live Agent (2)	Abandon Rate (%) (3=1/2*100)
Jan.	2,802	151,297	1.90%
Feb.	2,775	130,457	2.10%
Mar.	3,369	148,406	2.30%
Apr.	2,900	155,738	1.90%
May	3,271	171,658	1.90%
Jun.	2,997	161,867	1.90%
Jul.	3,790	170,683	2.20%
Aug.	3,112	156,131	2.00%
Sept.	2,990	172,160	1.70%
Oct.	3,740	179,215	2.10%
Nov.	2,364	159,513	1.50%
Dec.	2,050	138,997	1.50%
TOTAL	36,160	1,896,122	1.90%

G.2.1.9.B - BILL PERFORMANCE

Measure Calculations: The utility is required to have a verifiable Quality Assurance Program ("QAP") in place. Manual checks must be done to validate billing data when meter reads fall outside criteria (as set by the QAP) for excessively high or low usage.

OEB Approved Standard: No specific metric is attached to this requirement.

Month	Total Number of Billings	Total Number of Manual Checks Done as per QAP	Total Number of Manual Checks Done When Meter Reads Show Excessively High Usage Vs. QAP Criteria	Total Number of Manual Checks Done When Meter Reads Show Excessively Low Usage Vs. QAP Criteria
	(1)	(2)	(3)**	(5)**
January	2,132,712	38,726	11,258	
February	1,951,443	29,191	9,597	
March	2,107,527	29,374	11,295	
April	2,074,240	35,613	16,949	
May	2,115,596	35,768	19,479	
June	2,110,123	38,467	21,875	
July	2,127,261	38,047	21,217	
August	2,151,430	50,765	21,743	
September	2,177,124	48,981	22,116	
October	2,220,081	46,214	21,918	
November	2,042,336	34,195	14,329	
December	2,261,708	37,595	12,640	
Total	25,471,581	462,936	204,416	

**volume in Column 3 includes both high & low checks

Witnesses: K. Lakatos-Hayward
L. Parrington

Brief Explanation for Excessively High Usage (In 100 Words or less) (4)	

1. Bills that exceed our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly (e.g. backwards or digits like and 8 or 6 may have been visually misread).
3. An actual read could be higher following a number of estimates.
4. The historical usage on the account might that suggest that the customer's usage increases at a particular times each year. (eg. Pool heaters)
5. The customer has installed additional and/or upgraded gas appliances.

Brief Explanation for Excessively Low Usage (in 100 Words or less) (6)	

1. Bills that are below our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly e.g. backwards or digits like and 8 or 6 may have been visually misread.
3. An actual read could be lower following a number of estimates.
4. The historical usage on the account might that suggest that the customer's usage is reduced or stops altogether for certain periods each year.
5. The customer has removed or discontinued use of gas appliances.

G.2.1.9.C - METER READING PERFORMANCE

G.2.1.9.C.1 - Meter Reading Performance Measurement (MRPM)

Measure Calculations: MRPM = Number of meters with no read for 4 consecutive months or more divided by the total number of active meters to be read.

OEB Approved Standard: Measurement shall not exceed 0.5% on a yearly basis.

Month	Number of Meters with No Read for 4 Consecutive Months or More (1)	Total Number of Active Meters to be Read (2)	Meter Performance Measurement (%) (3=1/2*100)
Jan	15,760	2,073,183	0.8%
Feb	29,925	2,074,762	1.4%
Mar	47,626	2,076,410	2.3%
Apr	19,626	2,078,140	0.9%
May	8,638	2,080,606	0.4%
Jun	6,710	2,082,689	0.3%
Jul	6,278	2,085,843	0.3%
Aug	7,258	2,088,936	0.3%
Sep	8,097	2,092,433	0.4%
Oct	7,611	2,096,113	0.4%
Nov	7,033	2,100,387	0.3%
Dec	7,601	2,103,085	0.4%
Total	172,163	25,032,587	0.7%

The largest contributing factor to the Meter Reading Performance SQR result was inclement weather experienced in the winter of 2013/2014. The colder winter season created access barriers and caused injuries (through slips, trips and falls) that prevented meter readers from obtaining readings; the frequency of encountering such barriers was significantly higher (300,000+) than in prior years. Enbridge performed outbound calling campaigns to request customer readings and made additional visits to properties on off-peak hours to try to access the meter and obtain a reading in an attempt to mitigate the barriers noted above.

Witnesses: K. Lakatos-Hayward
L. Parrington

Enbridge continues to make enhancements to reporting so that the Company is quickly identifying, and acting upon, meters that are accumulating estimates through site visits and is using a variety of means of contacting the customer to set up a meter reading appointment.

G.2.1.9.D - SERVICE APPOINTMENTS RESPONSE TIME

G.2.1.9.D.1 - Appointments Met Within the Designated Time Period (AMWDTP)
Measure Calculations: AMWDTP = Number of appointments met within the 4 hour time on the scheduled date divided by the total number of appointments scheduled in the reporting month.
OEB Approved Standard: Minimum Performance Standard shall be 85% average over a year.

Month	Number of Appointments Met Within the 4-Hour Time on the Scheduled Date (1)	Total Number of Appointments Scheduled in the Reporting Month (2)	Appointments Met Within the Designated Time Period (%) (3=1/2*100)
Jan	4,318	4,476	96.50%
Feb	3,143	3,262	96.40%
Mar	3,347	3,498	95.70%
Apr	3,574	3,739	95.60%
May	4,189	4,374	95.80%
Jun	3,994	4,156	96.10%
Jul	3,836	4,007	95.70%
Aug	3,933	4,154	94.70%
Sep	4,926	5,221	94.30%
Oct	5,961	6,363	93.70%
Nov	5,015	5,329	94.10%
Dec	3,610	3,848	93.80%
Total	49,846	52,427	95.10%

Witnesses: K. Lakatos-Hayward
L. Parrington

G.2.1.9.D.2 - Time to Reschedule a Missed Appointment (TRMA)
Measure Calculations: TRMA = this measurement tracks the time taken by the utility to contact the consumer to offer to reschedule a missed appointment. This includes appointments for meter-related customer requests or other customer requested work such as installations, meter reads, and reconnections appointments not due to non-payment. At minimum the distributor must contact the customer to reschedule the work within 2 hours of the end of the original appointment.
OEB Approved Standard: Minimum Performance Standard shall be 100% of affected customers will receive a call from the utility offering to reschedule work within 2 hours of the end of the original appointment time.

Month	Total Number of Customers Appointments Missed (1)	Total Number of Customers Who Did Receive a Call Offering to Reschedule Within 2 Hours of the End of the Original Appointment Time Missed (2)	Brief Explanation of the Reasons Customers Did Not Receive a Call Within the Time Limit (In 50 Words) (3)	Percentage of Customers who Did Receive a Call Divided by the Total Number of Customer Appointments Missed (%) (4=2/1*100)
Jan	140	134	6 calls missed; 4 calls arrived later than 2 hours, 2 rescheduled after 2 hour limit without notifying customer	95.7%
Feb	102	100	2 calls missed; 2 calls arrived later than 2 hours	98.0%
Mar	120	119	1 call missed; 1 rescheduled after 2 hour limit without notifying customer	99.2%
Apr	125	121	4 calls missed; 3 calls arrived later than 2 hours, 1 rescheduled after 2 hour limit without notifying customer	96.8%
May	131	126	5 calls missed; 4 calls arrived later than 2 hours, 1 rescheduled after 2 hour limit without notifying customer	96.2%

Witnesses: K. Lakatos-Hayward
L. Parrington

Month	Total Number of Customers Appointments Missed (1)	Total Number of Customers Who Did Receive a Call Offering to Reschedule Within 2 Hours of the End of the Original Appointment Time Missed (2)	Brief Explanation of the Reasons Customers Did Not Receive a Call Within the Time Limit (In 50 Words) (3)	Percentage of Customers who Did Receive a Call Divided by the Total Number of Customer Appointments Missed (%) (4=2/1*100)
Jun	114	109	5 calls missed;2 calls arrived later than 2 hours, 3 rescheduled after 2 hour limit without notifying customer	95.6%
Jul	104	98	6 calls missed; 3 calls arrived later than 2 hours 3 rescheduled after 2 hour limit without notifying customer	94.2%
Aug	124	115	9 calls missed; 5 calls arrived later than 2 hours, 4 rescheduled after 2 hour limit without notifying customer	92.7%
Sep	169	165	4 calls missed; 4 calls arrived later than 2 hours	97.6%
Oct	229	220	9 calls missed; 5 calls arrived later than 2 hours, 4 rescheduled after 2 hour limit without notifying customer	96.1%
Nov	213	201	12 calls missed; 7 calls arrived later than 2 hours, 5 rescheduled after 2 hour limit without notifying customer	94.4%
Dec	143	129	14 calls missed; 5 calls arrived later than 2 hours, 9 rescheduled after 2 hour limit without notifying customer	90.2%
Total	1714	1637	As noted above.	95.5%

Witnesses: K. Lakatos-Hayward
L. Parrington

G.2.1.9.E - GAS EMERGENCY RESPONSE

G.2.1.9.E.1 - Percentage of Emergency Calls Responded Within One Hour (ECRWOH)

Measure Calculations: ECRWOH = Number of emergency calls responded to within 60 minutes divided by the total number of emergency calls received.

OEB Approved Standard: Measurement shall be that 90% of customers have received responses within 60 minutes of their call reaching a live person calculated on an annual basis.

Month	Number of Emergency Calls Responded to Within 60 Minutes (1)	Total Number of Emergency Calls Received (2)	Percentage of Emergency Calls Responded Within One Hour (%) (3=1/2*100)
Jan	5,957	6,260	95.2%
Feb	4,375	4,534	96.5%
Mar	4,626	4,798	96.4%
Apr	4,317	4,418	97.7%
May	4,476	4,591	97.5%
Jun	3,900	3,990	97.7%
Jul	3,501	3,582	97.7%
Aug	3,317	3,396	97.7%
Sep	4,038	4,126	97.9%
Oct	4,860	4,993	97.3%
Nov	5,581	5,800	96.2%
Dec	4,629	4,791	96.6%
Total	53,577	55,279	96.9%

G.2.1.9.F - CUSTOMER COMPLAINT WRITTEN RESPONSE

G.2.1.9.F.1 - Number of Days to Provide a Written Response (NDPAWR)

Measure Calculations: NDPAWR = Number of complaints requiring a written response responded to within 10 days divided by the total number of complaints requiring a written response.

OEB Approved Standard: Measurement shall be that 80% of customers have received written responses in 10 days of the distributor receiving the complaint.

Month	Number of Complaints Requiring a Written Response Responded to Within 10 Days (1)	Total Number of Complaints Requiring a Written Response (2)	NDPAWR Percentage (%) (3=1/2*100)
Jan.	4	4	100.00%
Feb.	2	2	100.00%
Mar.	4	4	100.00%
Apr.	1	1	100.00%
May	4	5	80.00%
Jun.	1	1	100.00%
Jul.	3	4	75.00%
Aug.	2	2	100.00%
Sept.	3	3	100.00%
Oct.	1	1	100.00%
Nov.	1	1	100.00%
Dec.	2	2	100.00%
TOTAL	28	30	93.33%

Witnesses: K. Lakatos-Hayward
L. Parrington

G.2.1.9.G - RECONNECTION RESPONSE TIME

G.2.1.9.G.1 - Number of Days to Reconnect A Customer (NDTRAC)

Measure Calculations: NDTRAC = Number of reconnections completed within 2 business days divided by the total number of reconnections completed.

OEB Approved Standard: Measurement shall be that 85% of customers are reconnected within 2 business days of bringing their accounts into good standing and will be tracked on a monthly basis.

Month	Number of Reconnections Completed Within 2 Business Days (1)	Total Number of Reconnections Completed (2)	Number of Days to Reconnect a Customer Percentage (%) (3=1/2*100)
Jan	758	862	87.9%
Feb	391	446	87.7%
Mar	377	425	88.7%
Apr	978	1,030	95.0%
May	5,116	5,272	97.0%
Jun	5,030	5,252	95.8%
Jul	4,976	5,192	95.8%
Aug	4,781	5,019	95.3%
Sep	5,293	5,566	95.1%
Oct	5,436	5,961	91.2%
Nov	3,471	3,881	89.4%
Dec	1,077	1,181	91.2%
Total	37,684	40,087	94.0%

Witnesses: K. Lakatos-Hayward
L. Parrington

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2014

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 related financial information, including Management's Discussion and Analysis (MD&A). The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, includes directors who are unrelated and independent, and has a specific responsibility to oversee management's efforts to fulfill 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 U.S. GAAP 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)

Glenn W. Beaumont
President

(Signed)

William M. Ramos
Vice President, Finance & Regulatory

February 18, 2015

February 18, 2015

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, 2014 and December 31, 2013 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2014, 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 accounting principles generally accepted in the United States of America 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.

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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, 2014 and December 31, 2013 and its results of operations and its cash flows for each of the three years in the period ended December 31, 2014 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Gas commodity and distribution revenue *(Note 20)*	**2,803**	2,221	1,869
Transportation of gas for customers	**305**	328	345
	3,108	2,549	2,214
Gas commodity and distribution costs, excluding depreciation *(Note 20)*	**(2,046)**	(1,480)	(1,229)
	1,062	1,069	985
Other revenue *(Note 4)*	**92**	97	202
	1,154	1,166	1,187
Expenses			
Operating and administrative *(Note 20)*	**493**	496	489
Depreciation and amortization *(Notes 3, 7 and 9)*	**286**	304	320
Earnings sharing *(Note 4)*	**12**	-	10
	791	800	819
	363	366	368
Other income	**66**	65	63
Interest expense, net *(Notes 11, 16 and 20)*	**(177)**	(171)	(170)
	252	260	261
Income taxes *(Note 17)*	**(6)**	(43)	(53)
Earnings from continuing operations	**246**	217	208
Discontinued operations *(Note 5)*			
Earnings from discontinued operations before income taxes	**-**	-	6
Income taxes from discontinued operations	**-**	-	(2)
Earnings from discontinued operations	**-**	-	4
Earnings	**246**	217	212
Preference share dividends *(Note 13)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**244**	215	210

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings	**246**	217	212
Other comprehensive income/(loss), net of tax *(Notes 15 and 16)*			
Change in unrealized gain/(loss) on cash flow hedges	**(62)**	81	(1)
Reclassification to earnings of realized loss on cash flow hedges	**-**	1	2
Reclassification to earnings of unrealized gain on cash flow hedges	**-**	(2)	-
Actuarial gain/(loss) on other postretirement benefits *(Note 18)*	**(7)**	10	(3)
Change in foreign currency translation adjustment	**3**	1	-
Other comprehensive income/(loss)	**(66)**	91	(2)
Comprehensive income	**180**	308	210
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**178**	306	208

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Preference shares *(Note 13)*	**100**	100	100
Common shares *(Note 13)*			
Balance at beginning of year	**1,287**	1,137	1,137
Common shares issued	**150**	150	-
Balance at end of year	**1,437**	1,287	1,137
Additional paid-in capital			
Balance at beginning of year	**1,148**	1,148	1,131
Disposition *(Note 5)*	**-**	-	17
Balance at end of year	**1,148**	1,148	1,148
Retained earnings/(deficit)			
Balance at beginning of year	**22**	7	(2)
Earnings attributable to the common shareholder	**244**	215	210
Common share dividends declared	**(204)**	(200)	(201)
Balance at end of year	**62**	22	7
Accumulated other comprehensive income/(loss) *(Note 15)*			
Balance at beginning of year	**65**	(26)	(24)
Other comprehensive income/(loss)	**(66)**	91	(2)
Balance at end of year	**(1)**	65	(26)
Total shareholders' equity	**2,746**	2,622	2,366

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Operating activities			
Earnings	**246**	217	212
Earnings from discontinued operations	**-**	-	(4)
Depreciation and amortization	**286**	304	320
Deferred income taxes	**4**	(9)	20
Refund of revenues *(Note 4)*	**52**	-	-
Recognition of regulatory asset *(Note 4)*	**-**	-	(89)
Other	**13**	12	13
Premium/(discount) on issuance of term notes	**(1)**	12	-
Changes in operating assets and liabilities *(Note 19)*	**(1,014)**	(86)	71
Cash provided by/(used) continuing operations	**(414)**	450	543
Cash provided by discontinued operations *(Note 5)*	**-**	-	12
	(414)	450	555
Investing activities			
Additions to property, plant and equipment	**(601)**	(519)	(414)
Additions to intangible assets	**(36)**	(34)	(38)
Change in construction payable	**11**	6	(11)
Proceeds on sale of assets *(Note 5)*	**-**	-	72
	(626)	(547)	(391)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**569**	(210)	33
Net change in short-term note payable to affiliate company *(Note 20)*	**189**	2	5
Term note issues	**730**	400	-
Term note repayments	**(400)**	-	-
Common shares issued *(Note 13)*	**150**	150	-
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(203)**	(200)	(206)
Other	**(2)**	(2)	-
	1,031	138	(170)
Increase/(decrease) in cash and cash equivalents	**(9)**	41	(6)
Cash and cash equivalents at beginning of year	**44**	3	9
Cash and cash equivalents at end of year	**35**	44	3
Cash and cash equivalents – discontinued operations *(Note 5)*	**-**	-	-
Cash and cash equivalents – continuing operations	**35**	44	3
Supplementary cash flow information			
Income taxes paid	**23**	42	31
Interest paid *(Note 11)*	**191**	169	176

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2014**	2013
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**35**	44
Accounts receivable and other *(Notes 4, 6, 16, 17 and 20)*	**1,189**	706
Gas inventories *(Note 2)*	**563**	382
	1,787	1,132
Property, plant and equipment, net *(Note 7)*	**6,268**	5,869
Investment in affiliate company *(Notes 16 and 20)*	**825**	825
Deferred amounts and other assets *(Notes 4, 8, 16 and 17)*	**738**	379
Intangible assets, net *(Note 9)*	**161**	174
	9,779	8,379
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**9**	4
Short-term borrowings *(Note 11)*	**938**	374
Short-term borrowings from affiliate *(Notes 11 and 20)*	**204**	15
Accounts payable and other *(Notes 4, 10, 16 and 20)*	**974**	769
Current maturities of long-term debt *(Note 11)*	**2**	400
	2,127	1,562
Long-term debt *(Note 11)*	**3,125**	2,399
Other long-term liabilities *(Notes 4, 12 and 16)*	**943**	1,026
Deferred income taxes *(Note 17)*	**463**	395
Loans from affiliate company *(Notes 11 and 20)*	**375**	375
	7,033	5,757
Commitments and contingencies *(Notes 20 and 21)*		
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; 4 outstanding at December 31, 2014 and 2013)*	**100**	100
Common shares *(159 and 151 outstanding at December 31, 2014 and 2013, respectively)*	**1,437**	1,287
Additional paid-in capital	**1,148**	1,148
Retained earnings	**62**	22
Accumulated other comprehensive income/(loss) *(Note 15)*	**(1)**	65
	2,746	2,622
	9,779	8,379

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

Approved by the Board of Directors:

(Signed)

Glenn W. Beaumont
President

(Signed)

J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

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 regulated and unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada until 2018.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of consolidated financial statements in conformity with U.S. 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 4)*; unbilled revenues *(Note 6)*; allowance for doubtful accounts *(Note 6)*; depreciation rates and carrying value of property, plant and equipment *(Notes 2 and 7)*; amortization rates and carrying value of intangible assets *(Note 9)*; valuation of stock-based compensation *(Note 14)*; fair value of financial instruments *(Note 16)*; provisions for income taxes *(Note 17)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 18);* commitments and contingencies *(Note 21)*; and fair value of asset retirement obligations (ARO). Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. 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 ratemaking 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 U.S. GAAP for non rate-regulated entities *(Note 4)*.

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

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

PUSH-DOWN ACCOUNTING
The Company elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships
The Company uses derivative financial instruments to manage its exposure to changes in 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 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 at December 31, 2014 or 2013.

Cash Flow Hedges
The Company uses cash flow hedges to manage its exposure to 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/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. 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 at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Classification of Derivatives
The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset
Assets and liabilities arising from derivative instruments may be 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 Deferred amounts and other assets. 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. Deferred 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. Deferred 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 approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of deferred income taxes related to temporary differences. A corresponding deferred income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates (*Note 4*).

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS

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

The Company extinguishes liabilities when a creditor has relieved the Company of its obligation, which occurs when the Company's financial institution honours a cheque that the creditor has presented for payment. Accordingly, obligations for which the Company has issued cheque payments that have not been presented to the financial institution totaling $23 million as of December 31, 2014 (2013 - $9 million) are included in Accounts payable and other on the Consolidated Statements of Financial Position.

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.

Included in, or deducted from, physical 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, 2014, $33 million (2013 - $28 million) of natural gas was held on behalf of transportation service customers. These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

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. Gains and losses from the disposal of assets not subject to the pool method of accounting, such as land, are reflected in earnings. 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 primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; derivative financial instruments; and deferred financing costs.

INTANGIBLE ASSETS
Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS
ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. ARO are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS
The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2014, new mortality assumptions were adopted by the Company for the measurement of the December 31, 2014 benefit obligations. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates, in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

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.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contributions occur.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company expects to recover pension expense in future rates and therefore records a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012, a regulatory asset related to OPEB obligation was not recorded as a rate order allowing for the recovery of these costs in rates had not yet been obtained. Commencing in 2012, pursuant to a specific rate order allowing for recovery in rates of OPEB costs determined on an accrual basis, a corresponding regulatory asset was recognized. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares. The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS AND CONTINGENCIES
Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements
Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Extraordinary and Unusual Items
ASU 2015-01 was issued in January 2015 and eliminates the concept of extraordinary items from GAAP. Entities will no longer be required to separately classify and present extraordinary events in the income statement, net of tax, after income from continuing operations. This accounting update is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. The adoption of the pronouncement is not anticipated to have an impact on the consolidated financial statements.

Revenue from Contracts with Customers
ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
ASU 2014-8 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively. The adoption of the pronouncement is not anticipated to have an impact on the Company’s consolidated financial statements.

CHANGES IN ACCOUNTING ESTIMATES

Depreciation Rates
In 2014, the Company revised depreciation rates based on the results of a new net negative salvage study which was approved by the Ontario Energy Board (OEB) as part of the 2014 to 2018 customized incentive regulation (IR) plan. The revised rates decreased depreciation and amortization expense by $44 million for the year ended December 31, 2014.

4. 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
The OEB issued a decision in July 2014, with a subsequent decision and rate order in August 2014 on the Company's customized IR application for the setting of rates for the period of 2014 through 2018. The customized IR plan requires allowed revenue, and consequently rates, to be updated for select items. The OEB also approved the adoption of a new approach for determining net negative salvage percentages to be included within the Company's depreciation rates. Under the customized IR plan, the Company shares equally with customers, earnings above the approved base return.

Under the customized IR plan, the Company will continue to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 – Regulated Operations.

For the year ended December 31, 2013, Enbridge Gas Distribution's rates were set pursuant to an OEB approved settlement agreement and decision related to its 2013 cost of service (COS) rate application. For the years ended December 31, 2014, 2013 and 2012, St. Lawrence's rates were set using a COS methodology. Under COS, revenues are set to recover costs and to earn a rate of return on the deemed common equity component of rate base. Costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, interest and income taxes. 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 2014 and 2013 COS, St. Lawrence's revenues were set to earn a rate of return on the deemed common equity component of rate base. Gas costs are not recovered through revenue rates, but are set separately in gas cost rates. Under COS, it is the responsibility of Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

For the year ended December 31, 2012, Enbridge Gas Distribution's rates were set using its OEB approved revenue per customer cap IR methodology, which was in place from 2008 through 2012. The IR methodology adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions. Under the IR mechanism, Enbridge Gas Distribution was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis.

During the years ended December 31, 2014, 2013 and 2012, the cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution
Enbridge Gas Distribution's rates for 2014 included an after-tax rate of return on common equity of 9.36% (2013 - 8.93% and 2012 - 8.39%) based on a 36% (2013 and 2012 - 36%) deemed common equity component of rate base.

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, 2014 (2013 and 2012 - 10.5%) based on a 50% (2013 and 2012 - 50%) deemed common equity component of rate base. Any earnings above a return on equity of 11% (2013 and 2012 - 11%) were shared equally with customers. The calculation of such earnings was cumulative from January 1, 2010 to December 31, 2014 and resulted in no sharing impact as at December 31, 2014 (2013 and 2012 - nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities
As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. 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. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

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

December 31,	**2014**	2013	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Purchased gas variance[1]	**673**	(6)	AR/DA	*
Deferred income taxes[2]	**270**	209	AP/DA	*
Pension plans, net[3]	**90**	2	DA/OLTL	*
OPEB[4]	**84**	89	AR/DA	18
Constant dollar net salvage adjustment[5]	**37**	-	DA	*
Unabsorbed demand cost[6]	**14**	-	AR	*
Design day criteria transportation[7]	**13**	-	AR	*
Demand side management incentive[8]	**13**	16	AR	*
Unaccounted for gas variance[9]	**13**	8	AR	1
Customer care CIS rate smoothing deferral[10]	**8**	5	DA	4
Deferred rate hearing costs[11]	**2**	4	AR	2
Average use true-up variance[12]	**1**	10	AR/AP	*
Future removal and site restoration reserves[13]	**(536)**	(905)	OLTL	*
Site restoration clearance adjustment[14]	**(283)**	-	AP/OLTL	4
Revenue adjustment[15]	**(52)**	-	AP	1
Transactional services deferral[16]	**(26)**	(51)	AP	1
Earnings sharing deferral[17]	**(12)**	(7)	AP	*
Storage and transportation deferral[18]	**(3)**	(3)	AP	1
Post-retirement true-up variance[19]	**(3)**	3	AR/AP/OLTL	*
Other regulatory assets and liabilities	**(3)**	1	***	***
	300	(625)		
St. Lawrence				
Other regulatory assets and liabilities	**5**	(1)	***	***
	5	(1)		
	305	(626)		

* 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 *Purchased gas variance (PGVA) 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 on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. In the*

absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs, excluding depreciation 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.

2 *The deferred income taxes balance represents the regulatory offset to deferred 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 the temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

3 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

4 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order, which allows the amount to be collected in rates over a 20-year period commencing in 2013. In the absence of rate regulation, this regulatory balance and related earnings impact would not be recorded.*

5 *The Constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the site restoration clearance adjustment. At the end of 2018 any residual balance will be cleared in a post 2018 true up, ensuring that the actual amount cleared is equivalent to the required $380 million.*

6 *The Unabsorbed demand cost deferral account (UDCDA) represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet increased requirements resulting from the Peak Gas Design Day Criteria (PGDDC). Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years. The balance for 2014 captures the cost consequences of unutilized transportation capacity above the amount associated with the 2014 Design day criteria transportation deferral account (DDCTDA). In the absence of rate regulation, these costs would be expensed as incurred.*

7 *DDCTDA balance represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet increased requirements resulting from the PGDDC. Enbridge Gas Distribution updated its PGDDC in 2013 and 2014. The impact of this update was phased in equally over the two years. The heating degree days used within its design day criteria for 2013 and 2014's design day criteria were updated. The balance for 2014 captures the cost consequences of unutilized transportation capacity associated with the 2014 DDCTDA. In the absence of rate regulation, these costs would be expensed as incurred.*

8 *Demand side management incentive deferral account (DSMIDA), previously referred to as shared savings mechanism deferral account, 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 DSMIDA 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.*

9 *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.*

10 *Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance will accumulate during 2013 to 2015 when the cost per customer exceeds the cost approved for recovery in rates. The balance will be drawn down during 2016 to 2018 when the cost per customer is lower than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

11 *Deferred rate hearing costs variance account (OHCVA) is rate hearing costs incurred by Enbridge Gas Distribution for the regulatory process. Historically, Enbridge Gas Distribution had been granted OEB approval for recovery of such hearing costs, generally within two years. Beginning in 2014, the OHCVA has been discontinued. In the absence of rate regulation, these costs would be expensed as incurred.*

12 *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 weather 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, this regulatory balance and the related earnings impact would not be recorded.*

13 *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.*

14 The Site restoration clearance adjustment represents the amount, that was determined by the OEB, of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term. This was a result of the OEB's approval of the adoption of a new approach for determining net negative salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves. There would be no change in the treatment of this item in the absence of rate regulation.

15 The revenue adjustment represents the revenue variance between interim rates, which were in place from January 2014 to September 2014, and the final OEB approved 2014 rates, which were implemented in October 2014, but effective in January 2014. The revenue adjustment balance is the 2014 OEB approved revenue adjustment amount to be refunded to customers in January 2015. There would be no change in the treatment of this item in the absence of rate regulation.

16 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.

17 Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the customized IR plan applicable to 2014. The earnings sharing is payable to customers and represented 50% of normalized 2014 U.S. GAAP earnings represented by the ROE in excess of the allowed utility return on equity threshold applicable to Enbridge Gas Distribution under the customized IR. The December 31, 2014 balance related to the year ended December 31, 2014. Earnings sharing did not apply to the 2013 COS Settlement. There would be no change in the treatment of this item in the absence of rate regulation.

18 Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation, the actual cost of natural gas storage and transportation 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.

19 Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB 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 subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation, the variance would be included in earnings in the year incurred.

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.

In 2012, the Company received a rate order from the OEB permitting recovery of OPEB costs in the amount of $89 million. The rate order allows this amount to be collected in rates over a 20-year period commencing in 2013, and was presented in Other revenue for the year ended December 31, 2012. In the absence of rate regulation, this earnings impact would not have been recorded.

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 would be charged to earnings in the year incurred.

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2014, cumulative costs relating to this services contract of $166 million (2013 - $154 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, 2014, the net book value of these costs was $60 million (2013 - $73 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. Included in gas inventories at December 31, 2014 is $42 million (2013 - $40 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 and inventory would be recorded at the lower of cost or market value.

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

5. DISCONTINUED OPERATIONS

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million inclusive of deferred income tax recoveries of $10 million were recognized as Additional paid-in capital. No gain or loss was recognized in earnings on the disposition; however $5 million of cash income taxes incurred on the related capital gain remains as a charge to consolidated earnings for the year ended December 31, 2012.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**567**	54
Trade receivables	**372**	357
Unbilled revenues	**161**	211
Taxes receivable	**28**	9
Current deferred income taxes *(Note 17)*	**23**	2
Due from affiliates *(Note 20)*	**11**	13
Prepaid expenses	**8**	7
Short-term portion of derivative assets *(Note 16)*	**-**	36
Agent billing and collection receivable	**-**	15
Other	**52**	33
Allowance for doubtful accounts *(Note 16)*	**(33)**	(31)
	1,189	706

During the first quarter of 2014, increases in natural gas prices and colder than normal weather resulted in the Company accumulating a significant balance in its PGVA. Included in Accounts receivable and other at December 31, 2014 is $491 million (December 31, 2013 - $6 million in Accounts payable and other) which represents the PGVA balance that is expected to be recovered from customers within the next 12 months.

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2014**	2013
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**3,593**	3,342
Gas services	**2.3%**	**2,798**	2,667
Regulating and metering equipment	**5.8%**	**825**	781
Gas storage	**2.2%**	**323**	314
Right-of-way	**1.2%**	**52**	48
Computer technology	**36.1%**	**40**	36
Under construction	**-**	**307**	198
Construction materials inventory	**-**	**39**	35
Land	**-**	**24**	23
Other	**6.9%**	**289**	280
		8,290	7,724
Accumulated depreciation		**(2,115)**	(1,949)
		6,175	5,775
Unregulated property, plant and equipment			
Gas storage	**2.2%**	**88**	87
Other	**8.1%**	**27**	24
		115	111
Accumulated depreciation		**(22)**	(17)
		93	94
Property, plant and equipment, net		**6,268**	5,869

Depreciation expense, including amounts collected for future removal and site restoration costs, was $237 million for the year ended December 31, 2014 (2013 - $267 million, 2012 - $289 million). Additional information about the impact of the revised depreciation rates is included in Note 3.

8. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**711**	312
Deferred financing costs	**12**	11
Deferred income taxes *(Note 17)*	**8**	1
Pension and OPEB asset *(Note 18)*	**4**	8
Long-term portion of derivative assets *(Note 16)*	**-**	46
Other	**3**	1
	738	379

At December 31, 2014, deferred amounts of $34 million (2013 - $31 million) were subject to amortization and are presented net of accumulated amortization of $22 million (2013 - $20 million). Amortization expense for the year ended December 31, 2014 was $2 million (2013 and 2012 - $2 million).

In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. Included in Deferred amounts and other assets at December 31, 2014 is $182 million (2013 - nil) which represents the portion of the PGVA balance that is expected to be recovered beyond the next 12 months.

9. INTANGIBLE ASSETS

December 31, 2014	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**24.1%**	**198**	**(97)**	**101**
CIS	**10.0%**	**127**	**(67)**	**60**
		325	**(164)**	**161**

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	22.8%	162	(61)	101
CIS	10.0%	127	(54)	73
		289	(115)	174

Intangible assets include $23 million of work-in-progress as at December 31, 2014 (2013 - $19 million). Total amortization expense for intangible assets was $49 million for the year ended December 31, 2014 (2013 - $37 million, 2012 - $31 million). The Company expects aggregate amortization expense for the years ending December 31, 2015 through 2019 of $43 million, $49 million, $47 million, $45 million and $41 million, respectively.

10. ACCOUNTS PAYABLE AND OTHER

December 31,	**2014**	2013
(millions of Canadian dollars)		
Operating accrued liabilities	**365**	329
Regulatory liabilities *(Note 4)*	**233**	76
Budget billing plan payable	**137**	82
Security deposits	**61**	62
Dividends payable	**52**	51
Due to affiliates *(Note 20)*	**44**	55
Trade payables	**27**	40
Interest payable	**27**	28
Taxes payable	**11**	22
Short-term portion of derivative liabilities *(Note 16)*	**6**	-
Current portion of OPEB liability *(Note 18)*	**4**	4
Agent billing and collection payable	**2**	-
Other	**5**	20
	974	769

Included in Accounts payable and other at December 31, 2014 is $52 million (2013 - nil) relating to the 2014 OEB approved revenue adjustment that will be refunded to customers as a result of the variance between interim rates and final OEB approved 2014 rates. Also included in Accounts payable and other at December 31, 2014 is $90 million (2013 - nil) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers within the next 12 months.

11. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2014**	2013
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes	4.73%	2017-2050	**3,025**	2,695
Commercial paper and credit facility draws, net[1]			**1,122**	382
Other[2]			**37**	26
Total debt			**4,269**	3,188
Current maturities			**(2)**	(400)
Short-term borrowings	1.32%		**(938)**	(374)
Short-term borrowings from affiliates *(Note 20)*	2.18%		**(204)**	(15)
Long-term debt			**3,125**	2,399
Loans from affiliate company *(Note 20)*			**375**	375

1 *Includes amounts drawn on uncommitted demand credit facilities.*
2 *Consists of note payable to affiliate company and debt premium.*

In April 2014, the Company issued $300 million of three-year medium-term notes at an interest rate of 1.85%. In June 2014, a new $1,000 million shelf prospectus was filed as a continuation of the Company's medium-term note program, which was last renewed in January 2013. The prospectus is effective for a 25-month period.

In August 2014, the Company issued $215 million of ten-year medium-term notes at an interest rate of 3.15% and $215 million of thirty-year medium-term notes at an interest rate of 4.00%.

For the years ending December 31, 2015 through 2019, medium-term note maturities are $2 million, $2 million, $502 million, $1 million and $1 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2015 through 2019 are $151 million, $151 million, $149 million, $135 million and $136 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Debentures and medium-term notes	**149**	138	139
Loans from affiliate company *(Note 20)*	**29**	27	27
Commercial paper and credit facility draws	**9**	4	2
Other interest and finance costs	**(4)**	9	8
Capitalized	**(6)**	(7)	(6)
	177	171	170

In 2014, total interest paid to third parties was $163 million (2013 and 2012 - $142 million) and total interest paid to affiliate company was $29 million (2013 - $27 million, 2012 - $34 million).

CREDIT FACILITIES

The Company currently has a $1,000 million commercial paper program limit that is backstopped by committed lines of credit of $1,000 million. The term of any commercial paper issued under this program may not exceed one year. The maturity date of the credit facility may be extended annually for an additional year from the end of the applicable revolving term, at the lender's option.

In June 2014, the Company obtained a new $300 million revolving credit facility from Enbridge Inc. which has a term out date in June 2015 and a maturity date in June 2016. As at December 31, 2014, $175 million was drawn on this credit facility. The Company also increased its external credit facility by $300 million to a total of $1,000 million and extended the term out date for an additional year to July 2015, with a maturity date in July 2016.

		December 31, 2014			December 31, 2013
	Maturity Dates	Total Facilities[1]	Draws[2]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2016	**1,300**	**1,110**	**190**	700
St. Lawrence Gas Company, Inc.	2019	**8**	**8**	**-**	13
Total credit facilities		**1,308**	**1,118**	**190**	713

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

In addition to the committed credit facilities noted above, St. Lawrence Gas Company, Inc. also has $6 million (2013 - $5 million) of uncommitted demand credit facilities, of which $2 million (2013 - $1 million) was unutilized as at December 31, 2014.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and draws bear interest at market rates.

The Company’s borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity over 18 months, covenants contained in the Company’s trust indenture require the pro forma long-term debt interest coverage ratio to be at least 2.0 times for 12 consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as U.S. GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of financing costs and intercompany interest expense less gains on asset dispositions divided by the annual interest requirement. 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, 2014, the Company was in compliance with this covenant.

12. OTHER LONG-TERM LIABILITIES

December 31,	**2014**	2013
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**740**	916
Pension and OPEB liabilities *(Note 18)*	**190**	104
Long-term portion of derivative liabilities *(Note 16)*	**5**	-
Other	**8**	6
	943	1,026

13. 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 preference shares.

COMMON SHARES

	2014		2013		2012	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**150.6**	**1,287**	142.3	1,137	142.3	1,137
Common shares issued	**8.3**	**150**	8.3	150	-	-
Balance at end of year	**158.9**	**1,437**	150.6	1,287	142.3	1,137

PREFERENCE SHARES

December 31, 2014, 2013, and 2012	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference 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 preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2014, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder’s option, into Group 2, Series D preference shares on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period. The Group 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

The Group 2, Series D preference shares can be redeemed, at the Company’s option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder’s option on July 1, 2019 and every five years thereafter.

14. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis. As of December 31, 2014, the Company did not have any employees that had options in the PBSO Plan.

INCENTIVE STOCK OPTIONS

Key employees of the Company 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.

December 31, 2014	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,490**	**28.81**		
Options granted	**468**	**48.81**		
Options exercised[1]	**(363)**	**20.19**		
Options cancelled	**(7)**	**31.87**		
Employee movements from other Enbridge companies	**77**	**30.07**		
Options outstanding at end of year	**2,665**	**33.53**	**6.3**	**48**
Options vested at end of year[2]	**1,529**	**26.02**	**4.8**	**39**

1 *The total intrinsic value of ISOs exercised during the year ended December 31, 2014 was $11 million (2013 - $7 million; 2012 - $11 million) and cash received by Enbridge on exercise was $5 million (2013 - $2 million; 2012 - $6 million).*

2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2014 was $2 million (2013 and 2012 - $2 million).*

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2014**	2013	2012
Fair value per option *(Canadian dollars)*[1]	**5.53**	5.27	4.81
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**16.9%**	17.4%	19.7%
Expected dividend yield[4]	**2.9%**	2.8%	3.0%
Risk-free interest rate[5]	**1.6%**	1.2%	1.3%

1 *Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $5.45 (2013 - $5.15; 2012 - $4.65) for Canadian employees and US$5.35 (2013 - US$5.63, 2012 - US$5.58) for United States employees.*

2 *The expected option term is based on historical exercise practice.*

3 *Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.*

4 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*

5 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.*

Compensation expense recorded for the year ended December 31, 2014 for ISOs was $4 million (2013 and 2012 - $3 million). At December 31, 2014, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $4 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company 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 share price for 20 days prior to the maturity of the grant 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 2012, 2013 and 2014 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 earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2014 expense, multipliers of two, based upon multiplier estimates at December 31, 2014, were used for each of the 2012, 2013 and 2014 PSU grants.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**19**		
Units granted	**15**		
Units matured[1]	**(9)**		
Dividend reinvestment	**1**		
Units outstanding at end of year	**26**	**1.6**	**3**

1 The total amount paid by Enbridge during the year ended December 31, 2014 for PSUs was $1 million (2013 - $2 million; 2012 - $1 million).

Compensation expense recorded for the year ended December 31, 2014 for PSUs was $5 million (2013 - $4 million; 2012 - $7 million). As of December 31, 2014, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $2 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a 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 for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2014	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**203**		
Units granted	**96**		
Units cancelled	**(9)**		
Units matured[1]	**(105)**		
Dividend reinvestment	**8**		
Employee movements from other Enbridge companies	**3**		
Units outstanding at end of year	**196**	**1.4**	**10**

1 The total amount paid by Enbridge during the year ended December 31, 2014 for RSUs was $5 million (2013 - $5 million; 2012 - $5 million).

Compensation expense recorded for the year ended December 31, 2014 for RSUs was $5 million (2013 - $5 million; 2012 - $5 million). As of December 31, 2014, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $6 million and is expected to be fully recognized over a weighted average period of approximately two years.

15. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI for the years ended December 31, 2014, 2013 and 2012, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2014	**70**	**(5)**	**-**	**65**
Other comprehensive income retained in AOCI	**(84)**	**3**	**(9)**	**(90)**
Other comprehensive income reclassified to earnings				
Interest rate contracts	**-**	**-**	**-**	**-**
	(84)	**3**	**(9)**	**(90)**
Tax impact				
Income tax on amounts retained in AOCI	**22**	**-**	**2**	**24**
	22	**-**	**2**	**24**
Balance at December 31, 2014	**8**	**(2)**	**(7)**	**(1)**

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2013	(10)	(6)	(10)	(26)
Other comprehensive income retained in AOCI	109	1	14	124
Other comprehensive income reclassified to earnings				
Interest rate contracts	(1)	-	-	(1)
	108	1	14	123
Tax impact				
Income tax on amounts retained in AOCI	(28)	-	(4)	(32)
	(28)	-	(4)	(32)
Balance at December 31, 2013	70	(5)	-	65

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(*millions of Canadian dollars*)				
Balance at January 1, 2012	(11)	(6)	(7)	(24)
Other comprehensive loss retained in AOCI	(1)	-	(4)	(5)
Other comprehensive loss reclassified to earnings				
Interest rate contracts	2	-	-	2
	1	-	(4)	(3)
Tax impact				
Income tax on amounts retained in AOCI	-	-	1	1
	-	-	1	1
Balance at December 31, 2012	(10)	(6)	(10)	(26)

16. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates and natural gas prices (collectively, market 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 risks to which the Company is exposed and the risk management instruments used to mitigate them.

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 in the exchange rate 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 (2013 - nil).

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. Pay fixed-receive floating interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

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. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2013 - nil).

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at December 31, 2014 or 2013.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2014	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts payable and other					
Interest rate contracts	**(6)**	**-**	**(6)**	**-**	**(6)**
Other long-term liabilities					
Interest rate contracts	**(5)**	**-**	**(5)**	**-**	**(5)**
Total net derivative liability					
Interest rate contracts	**(11)**	**-**	**(11)**	**-**	**(11)**

December 31, 2013	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable and other					
Interest rate contracts	36	-	36	-	36
Deferred amounts and other assets					
Interest rate contracts	46	-	46	-	46
Total net derivative asset					
Interest rate contracts	82	-	82	-	82

The Company's derivatives instruments mature through 2017 and have a notional principal of $346 million for interest rate contracts for short-term borrowings (2013 - $535 million), and $422 million for interest rate contracts on long-term debt (2013 - $747 million).

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(84)**	109	(1)
	(84)	109	(1)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**-**	(2)	(2)
	-	(2)	(2)
Amount of gains reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**-**	2	-
	-	2	-

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

The Company estimates that $1 million in AOCI 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. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 25 months at December 31, 2014.

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 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes, and, if necessary, additional liquidity is available through intercompany transactions with Enbridge Inc. and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current shelf prospectus with securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition to the Company's access to the Canadian public capital markets, the Company maintains committed credit facilities *(Note 11)* with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2014. 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.

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts *(Note 6),* which totaled $33 million at December 31, 2014 (December 31, 2013 - $31 million).

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.

Entering into derivative financial instruments may also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily 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.

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company had group credit concentration and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

	December 31, 2014	December 31, 2013
(millions of Canadian dollars)		
Canadian financial institutions	**-**	69
European financial institutions	**-**	13
	-	82

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. 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.

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. The Company does not have any derivative instruments classified as Level 1.

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 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. The Company does not have any derivative instruments classified as Level 3.

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2014, the Company had Level 2 derivative assets with fair value of nil (2013 - $82 million), and Level 2 derivative liabilities with fair value of $11 million (2013 - nil).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2014 or 2013.

Fair Value of Other Financial Instruments
The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted market prices are not available for fair value measurement in which case these investments are recorded at cost. The Company's investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2014, the fair value of the investment was $825 million (2013 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as of December 31, 2014 and 2013 the fair value approximated its cost and redemption value and therefore no amount was recognized in OCI.

The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor, and is classified as a Level 2 measurement. At December 31, 2014, the Company's long-term debt had a carrying value of $3,127 million (2013 - $2,799 million) and a fair value of $3,709 million (2013 - $3,161 million).

The fair value of other financial assets and liabilities other than derivative instruments approximates their cost due to the short period to maturity.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings from continuing operations before income taxes	**252**	260	261
Federal statutory income tax rate	**15.0%**	15.0%	15.0%
Federal income taxes at statutory rate	**38**	39	39
Increase/(decrease) resulting from:			
Provincial and state income taxes	**3**	19	18
Effects of rate regulated accounting[1]	**(25)**	(5)	(7)
Non-taxable intercompany distributions	**(9)**	(9)	(9)
Legislative changes and other rate differentials	**-**	-	8
Intercompany sale of investment[2]	**-**	-	3
Other[3]	**(1)**	(1)	1
Income taxes from continuing operations	**6**	43	53
Effective income tax rate	**2.4%**	16.5%	20.3%

1 *During 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted a decrease in income taxes from continuing operations of $26 million (2013 - nil).*

2 *In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund. As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer was eliminated, although cash income taxes of $5 million remained as a charge to earnings.*

3 *Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.*

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings from continuing operations before income taxes			
Canada	**249**	258	259
United States	**3**	2	2
	252	260	261
Current income taxes			
Canada	**2**	51	28
United States	**1**	1	1
	3	52	29
Deferred income taxes			
Canada	**3**	(9)	24
United States	**-**	-	-
	3	(9)	24
Income taxes from continuing operations	**6**	43	53

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(577)**	(560)
Financial derivatives	**(3)**	(25)
Deferrals	**-**	(13)
Regulatory assets	**(72)**	(56)
Other	**(1)**	(2)
Total deferred income tax liabilities	**(653)**	(656)
Deferred income tax assets		
Future removal and site restoration reserves	**143**	240
Deferrals	**53**	-
Retirement and postretirement benefits	**21**	23
Other	**4**	1
Total deferred income tax assets	**221**	264
Net deferred income tax liabilities	**(432)**	(392)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 6)*	**23**	2
Deferred amounts and other assets *(Note 8)*	**8**	1
Total deferred income tax assets	**31**	3
Liabilities		
Deferred income taxes	**(463)**	(395)
Total deferred income tax liabilities	**(463)**	(395)
Net deferred income tax liabilities	**(432)**	(392)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2014.

The Company has not provided for deferred income taxes on the difference between the carrying value of its foreign subsidiaries and their corresponding tax bases as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying value of the investment and its tax basis is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $21 million (2013 - $16 million). If such earning were remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and its subsidiaries are subject to taxation in Canada and the Unites States. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario). The Company's 2010 to 2013 taxation years are still open for audit in Canada.

18. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides either defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2014 was used to determine the plan assets and accrued benefit obligation for the pension plans.

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, 2013. The effective date of the next required actuarial valuation is December 31, 2016.

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.

OTHER POSTRETIREMENT BENEFITS
The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
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 plans using the accrual method.

	Pension		OPEB	
December 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**875**	905	**100**	112
Service cost	**25**	25	**2**	1
Interest cost	**43**	38	**6**	4
Actuarial loss/(gain)	**142**	(52)	**12**	(16)
Benefits paid	**(41)**	(40)	**(3)**	(2)
Other	**2**	(1)	**-**	1
Benefit obligation at end of year	**1,046**	875	**117**	100
Change in plan assets				
Fair value of plan assets at beginning of year	**866**	782	**9**	7
Actual return on plan assets	**96**	84	**2**	1
Employer's contributions	**41**	38	**5**	3
Benefits paid	**(41)**	(40)	**(3)**	(2)
Other	**(2)**	2	**-**	-
Fair value of plan assets at end of year	**960**	866	**13**	9
Underfunded status at end of year	**(86)**	(9)	**(104)**	(91)
Presented as follows:				
Deferred amounts and other assets *(Note 8)*	**4**	7	**-**	1
Accounts payable and other *(Note 10)*	**-**	-	**(4)**	(4)
Other long-term liabilities *(Note 12)*	**(90)**	(16)	**(100)**	(88)

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

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**4.0%**	5.0%	4.3%	**4.0%**	5.0%	4.3%
Average rate of salary increases	**3.7%**	3.5%	3.5%	**3.7%**	3.5%	3.5%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
(millions of Canadian dollars)						
Benefits earned during the year	**25**	25	21	**1**	1	2
Interest cost on projected benefit obligations	**43**	38	37	**6**	4	4
Expected return on plan assets	**(59)**	(52)	(49)	**(1)**	(1)	(1)
Amortization of prior service costs	**-**	1	1	**-**	-	-
Amortization of actuarial loss	**16**	28	30	**-**	2	1
Net defined benefit costs on an accrual basis	**25**	40	40	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**26**	41	41	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**9**	(14)	4
Total amount recognized in OCI	**-**	-	-	**9**	(14)	4
Total net benefit cost on an accrual basis and amount recognized in OCI	**26**	41	41	**15**	(8)	10

1 *Unamortized actuarial losses included in AOCI, before tax, were $9 million relating to OPEB at December 31, 2014 (2013 - nil, 2012 - $14 million).*

The Company estimates that approximately $19 million related to pension plans and OPEB at December 31, 2014 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Actuarial loss	**19**	**-**	**19**
	19	**-**	**19**

Regulatory adjustments were recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers, respectively, in future rates *(Note 4)*. For the year ended December 31, 2014, an offsetting regulatory liability of $6 million (2013 - regulatory asset of $3 million) has been recorded to the extent pension and OPEB costs are expected to be refunded to customers in future rates.

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consists of OEB approved pension and OPEB costs.

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

	Pension			OPEB		
Year ended December 31,	**2014**	2013	2012	**2014**	2013	2012
Discount rate	**5.0%**	4.3%	4.5%	**5.0%**	4.3%	4.5%
Average rate of return on pension plan assets	**6.8%**	6.8%	7.0%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	3.5%	5.0%

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	7.7%	4.3%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $14 million in the benefit obligation 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 benefit obligation and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds 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.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2014**	2013	**2014**	2013
Expected rate of return	**6.8%**	6.8%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2014, the pension assets were invested in 55% (2013 - 55%) in equity securities, 36% (2013 - 36%) in fixed income securities and 9% (2013 - 9%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $18 million (2013 - $18 million) have been excluded from the table below.

	2014				2013			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**14**	**-**	**-**	**14**	12	-	-	12
Fixed income securities								
Canadian government real return bonds	**71**	**-**	**-**	**71**	62	-	-	62
Canadian corporate bond index fund	**137**	**-**	**-**	**137**	122	-	-	122
Canadian government bond index fund	**131**	**-**	**-**	**131**	115	-	-	115
Canadian real return bond index fund	**-**	**-**	**-**	**-**	2	-	-	2
Corporate bonds and debentures	**4**	**-**	**-**	**4**	3	-	-	3
United States debt index fund	**2**	**-**	**-**	**2**	1	-	-	1
Equity								
Canadian equity securities	**71**	**-**	**-**	**71**	70	-	-	70
Canadian equity funds	**137**	**-**	**-**	**137**	118	-	-	118
United States equity securities	**1**	**-**	**-**	**1**	1	-	-	1
United States equity funds	**77**	**19**	**-**	**96**	65	17	-	82
Global equity funds	**149**	**63**	**-**	**212**	142	55	-	197
Infrastructure[4]	**-**	**-**	**30**	**30**	-	-	29	29
Real estate[5]	**-**	**-**	**39**	**39**	-	-	38	38
Forward currency contracts	**-**	**(3)**	**-**	**(3)**	-	(4)	-	(4)
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	-	-	-	-
Fixed income securities								
United States government and government agency bonds	**5**	**-**	**-**	**5**	3	-	-	3
Equity								
United States equity fund	**4**	**-**	**-**	**4**	3	-	-	3
Global equity fund	**3**	**-**	**-**	**3**	3	-	-	3

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund is established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd is established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2014**	2013
(millions of Canadian dollars)		
Balance at beginning of year	**67**	53
Unrealized and realized gains	**15**	4
Purchases and settlements, net	**(13)**	10
Balance at end of year	**69**	67

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Total contributions	**41**	39	**5**	3
Contributions expected to be paid in 2015	**4**		**5**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2015	2016	2017	2018	2019	2020-2024
(millions of Canadian dollars)						
Expected future benefit payments	46	48	50	53	55	304

19. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Regulatory assets	**(732)**	(31)	(86)
Regulatory liabilities	**(102)**	2	76
Accounts receivable and other[1]	**24**	(13)	73
Gas inventories	**(181)**	(41)	54
Deferred amounts and other assets[1]	**(3)**	(2)	89
Accounts payable and other[1]	**(75)**	80	(59)
Other long-term liabilities[1]	**55**	(81)	(76)
	(1,014)	(86)	71

1 The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.

20. RELATED PARTY TRANSACTIONS

All related party transactions, other than those disclosed under Other Transactions, are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
IPL System Inc. *(Note 16)*			
Dividend income	**63**	63	63
Interest expense	**27**	27	27
Enbridge Inc.			
Purchase of treasury and other management services	**41**	38	39
Interest expense	**2**	-	-
Tidal Energy Marketing Inc.			
Purchase of natural gas	**41**	30	11
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**57**	21	2
Aux Sable Canada LP			
Purchase of natural gas	**16**	-	-
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**31**	30	25
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**27**	24	24
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**26**	26	25
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**20**	19	18

The Company had related party balances as follows:

December 31,	**2014**	2013
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.)	**29**	15
Credit facility to affiliate company		
Enbridge Inc.	**175**	-
Other accounts receivable/(payable)		
Enbridge Pipelines Inc.	**(15)**	(15)
Aux Sable Canada LP	**(8)**	-
Enbridge Inc.	**(7)**	(5)
Tidal Energy Marketing Inc.	**(3)**	(7)
Tidal Energy Marketing (U.S.) LLC	**(3)**	(4)
Alliance Pipeline Limited Partnership (Canadian)	**(2)**	(2)
Alliance Pipeline Limited Partnership (U.S.)	**(2)**	(2)
Vector Pipeline Limited Partnership (U.S.)	**(2)**	(2)
IPL System Inc.	**-**	(15)
Gazifère Inc.	**6**	5

Financing Transactions

The Company has invested in Class D, non-voting, redeemable, retractable preference shares of IPL System Inc., an affiliate under common control. At December 31, 2014, the investment of $825 million (2013 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2014, 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 preference shares of the Company. For the year ended December 31, 2014, interest paid amounted to $27 million (2013 - $27 million).

In June 2014, the Company obtained a new $300 million revolving credit facility from Enbridge Inc. which has a term out date in June 2015 and a maturity date in June 2016. At December 31, 2014, the total drawings on the revolving credit facility were $175 million. For the year ended December 31, 2014, interest paid amounted to $2 million (2013 - nil).

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 on a cost recovery basis.

Natural Gas Purchases

The Company has contracted for the purchase of natural gas from Aux Sable Canada LP, Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under these contracts are nil.

Wholesale Service
These gas procurement and transportation 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 2015 to 2016 - $1,971 million, 2017 to 2018 - $570 million and thereafter - $286 million.

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 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund, an affiliated entity under common control, for cash proceeds of $72 million *(Note 5)*.

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 signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $5,328 million. The amounts which are expected to be paid in the next five years are $1,781 million, $904 million, $589 million, $436 million, and $411 million, respectively, and $1,207 million thereafter.

Minimum future payments under operating leases are estimated at $9 million in aggregate. Estimated annual lease payments for the years ended December 31, 2015 through 2019 are $4 million, $4 million, $1 million, nil and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $3 million for each of the years ended December 31, 2014, 2013 and 2012.

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 the required steps in the discovery process were not completed by the plaintiff. The Company has brought a motion to dismiss the plaintiff's action for delay. At present, it is unknown when or if 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 2014 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

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

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

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.

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2014

MANAGEMENT’S DISCUSSION AND ANALYSIS

This Management’s Discussion and Analysis (MD&A) dated February 18, 2015 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) as at and for the year ended December 31, 2014, which are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements prepared and MD&A for the year ended December 31, 2013. 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 over 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 regulated and unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

PERFORMANCE OVERVIEW

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to the common shareholder[1,5]	**244**	215	210
Earnings excluding the effect of weather[2]	**208**	206	233
Cash flow data			
Cash provided by/(used) continuing operations	**(414)**	450	543
Cash provided by discontinued operations	**-**	-	12
Cash used by investing activities	**(626)**	(547)	(391)
Cash provided/(used) by financing activities	**1,031**	138	(170)
Dividends			
Common share dividends declared	**204**	200	201
Dividends declared per common share	**1.34**	1.37	1.41
Preference share dividends declared	**2**	2	2
Dividends declared per preference share	**0.60**	0.60	0.60
Total revenues			
Gas commodity and distribution revenues	**2,803**	2,221	1,869
Transportation of gas for customers	**305**	328	345
Other revenue	**92**	97	202
Revenue from continuing operations	**3,200**	2,646	2,416
Revenue from discontinued operations	**-**	-	10
Total revenues	**3,200**	2,646	2,426
Total assets	**9,779**	8,379	7,915
Total long-term liabilities	**4,906**	4,195	4,218
Number of active customers[3] *(thousands)*	**2,098**	2,065	2,032
Heating degree days[4]			
Actual	**4,044**	3,746	3,194
Forecasted based on normal weather	**3,517**	3,668	3,532

1. *Includes earnings from discontinued operations of $4 million for the year ended December 31, 2012.*
2. *Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by U.S. GAAP. For more information on this non-GAAP measure see page 5.*
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.*
5. *Since the issuer is an indirect wholly owned subsidiary of Enbridge, earnings per share is not provided.*

EARNINGS ATTRIBUTABLE TO THE COMMON SHAREHOLDER

Earnings attributable to the common shareholder were $244 million for the year ended December 31, 2014 compared with $215 million for the year ended December 31, 2013. The increase was primarily due to colder weather, customer growth, lower depreciation expense and income taxes. This is partially offset by lower distribution rates and earnings sharing in 2014.

Earnings attributable to the common shareholder were $215 million for the year ended December 31, 2013 compared with $210 million for the year ended December 31, 2012. The increase was primarily due to colder weather, customer growth, the absence of earnings sharing in 2013 and higher demand side management incentive (DSMIDA) revenue which results from exceeding targets on delivery of energy efficiency programs for the promotion of energy efficient use of natural gas to customers. This was partially offset by a decrease in other revenue compared to the year ended December 31, 2012, as the Company received an OEB rate order in 2012 allowing the recognition of revenue and corresponding regulatory asset of $89 million related to other postretirement benefits (OPEB). The OEB 2013 Settlement established the Company's right to recover the OPEB regulatory asset over a 20-year period commencing in 2013. Additional information about the impact of the recognition of the OPEB regulatory asset is included in Note 4 of the 2014 Annual Consolidated Financial Statements.

EARNINGS EXCLUDING THE EFFECT OF WEATHER

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings attributable to the common shareholder	**244**	215	210
(Colder)/warmer than normal weather (after-tax impact)	**(36)**	(9)	23
Earnings excluding the effect of weather	**208**	206	233

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). As part of the 2014 to 2018 customized IR application, the Company forecast degree days for the Greater Toronto Area (GTA) using a combination of a 10-year moving average method and 20-year trend method. The methodology was approved by the OEB in July 2014.

Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the most recent weather data.

Earnings excluding the effect of weather were $208 million for the year ended December 31, 2014 compared with $206 million for the year ended December 31, 2013. The increase primarily resulted from customer growth, lower depreciation expense and income taxes. This is partially offset by lower distribution rates and earnings sharing in 2014.

Earnings excluding the effect of weather were $206 million for the year ended December 31, 2013 compared with $233 million for the year ended December 31, 2012. The decrease primarily resulted from lower other revenue due to OEB rate order and settlement allowing the recognition of an OPEB regulatory asset and corresponding revenue in the prior year. This was partially offset by customer growth, the absence of earnings sharing in 2013 and higher DSMIDA revenue.

REVENUES

Revenues from continuing operations for the year ended December 31, 2014 were $3,200 million compared with $2,646 million for the year ended December 31, 2013. The increase in revenues from continuing operations was primarily due to colder weather, customer growth, and higher commodity prices. This was partially offset by lower distribution rates and a decrease in Other revenue mainly due to lower DSMIDA revenue.

Revenues from continuing operations for the year ended December 31, 2013 were $2,646 million compared with $2,416 million for the year ended December 31, 2012. The increase in revenues from continuing operations was primarily due to colder weather, customer growth, higher commodity prices and higher DSMIDA revenue. This was partially offset by a decrease in Other revenue mainly due to an OEB rate order received in the prior year allowing the recognition of revenue and corresponding OPEB regulatory asset in 2012.

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 earnings/(loss); expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

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 of 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 of and demand for 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, particularly with respect to expected earnings/(loss) or estimated future dividends. 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, changes in tax law and tax rate increases, 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 applicable 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 gas distribution margin which represents gas commodity and distribution revenue and transportation of gas for customer revenue less gas commodity and distribution costs excluding depreciation. This MD&A also 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 these measures provides useful information to investors and the shareholder as it provides increased transparency and predictive value. Management uses these measures to set targets and assess performance of the Company. Gas distribution margin and earnings excluding the effect of weather are not measures that have standardized meanings prescribed by U.S. GAAP and are not considered a U.S. GAAP measure, therefore, these measures 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;
- maintain and enhance customer and stakeholder relationships;
- maintain a healthy and productive work environment;
- enhance governance, integrity and transparency in all business processes; and
- deliver shareholder value.

The Company's strategic initiatives are designed to protect and enhance its core business with a continued focus on optimizing performance. 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 when market conditions permit.

Operations safety and system integrity continues to be the Company's number one priority and sets the foundation for the Company's strategic plan. Core to this priority is the focus on system integrity, and environmental and safety programs, which charts the course for best-in-class practices.

RECENT DEVELOPMENTS

INCENTIVE REGULATION (IR) APPLICATION

In 2013, the Company filed a customized IR plan for the period 2014 to 2018. A decision from the OEB was provided on July 17, 2014, with a subsequent decision and rate order provided on August 22, 2014. The OEB approved the customized IR plan, with modifications, inclusive of the requested capital investment amounts and an incentive mechanism providing the opportunity to earn above the allowed return on equity. The OEB's decision also allowed for final 2014 rates to be implemented with the October 2014 Quarterly Rate Adjustment Mechanism, and was effective January 1, 2014.

The following summarizes the key terms of the approved customized IR plan:

Annual Allowed Revenue Updates – The OEB's decision approved final 2014 allowed revenues and rates. Within annual rate proceedings for 2015 through 2018, the customized IR plan requires allowed revenues, and corresponding rates, to be updated for select items. Volumes are updated annually to reflect updated customer additions, contract market volumes, and average use, reducing volumetric risk to the Company and ratepayers. The customer care, demand side management, pension and other post-employment benefits components of operating and maintenance costs will be updated annually and be treated as pass-through amounts from other approved mechanisms. Finally, the cost of capital will be updated annually. Return on equity will be updated using the OEB approved parameters, while financing costs will be updated to incorporate impact of actual debt issuances and a current forecast for future issuances. The annual updates reduce forecast risk, and ensure rates reflect current market conditions.

Future Removal and Site Restoration Costs - The OEB approved the adoption of a new approach for determining net negative salvage percentages to be included within the Company's approved depreciation rates, as compared to the traditional approach previously employed. The new approach results in lower net negative salvage percentages, and therefore lowers depreciation rates and future removal and site restoration reserves.

Earnings Sharing – To align the interest of customers with the Company's shareholder, an earnings sharing mechanism (ESM) forms part of the customized IR plan. 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 approved return on equity for that year, the over-earnings will be shared equally with customers.

Adjustments – There are several approved deferral and variance accounts that provide a level of protection for the Company and ratepayers for costs, or changes in operating conditions, that deviate from those assumed in developing the customized IR plan. The customized IR plan also includes a z-factor mechanism for the Company to recover expenses above a defined threshold, to the extent any such expenses result from new regulatory orders and/or changes in statutory obligations.

Off Ramps – An OEB review will be triggered if the Company's ROE on a normalized basis varies more than 300 basis points (either negatively or positively) relative to the approved ROE for that year. The review, if triggered, would determine the reasons for the variance in earnings and in such circumstances could result in adjustments to the customized IR plan or a return to Cost of Service regulation. The review would not have an impact on earnings for prior years.

EQUITY INJECTION BY PARENT COMPANY

In November 2014, the Company's parent company subscribed for and was issued an additional 8,319,468 common shares for proceeds of $150 million, which supported the Company's growth initiatives.

IMPACT OF INCREASES IN NATURAL GAS PRICES

As a result of increases in natural gas prices and significantly colder than normal weather during the first quarter of 2014, the Company accumulated a significant balance in its gas cost variance account related to the Company's costs to supply gas to customers ("PGVA"). In May 2014, the OEB issued a decision allowing a portion of the PGVA balance as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016. As at December 31, 2014, $491 million of the PGVA has been presented in Accounts receivable and other and $182 million has been presented in Deferred amounts and other assets in the consolidated statements of financial position. As a result, working capital balances are expected to remain elevated through early 2016. Additional liquidity facilities have been secured to accommodate this increase in working capital during the period costs are expected to be recovered. See *Liquidity and Capital Resources*.

GTA PROJECT

The Company is undertaking the expansion of its natural gas distribution system in the GTA to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. The GTA project involves the construction of two new segments of pipeline, a 27-kilometre 42-inch diameter pipeline and a 23-kilometre 36-inch diameter pipeline in Toronto, as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in the GTA. With the OEB approval received in January 2014, construction began in January 2015 and is expected to be completed by the end of 2015 at an estimated cost of approximately $756 million with expenditures to date of approximately $198 million.

FRANKLIN COUNTY EXPANSION PROJECT

In July 2012, St. Lawrence Gas Company Inc. (St. Lawrence), a wholly owned subsidiary, received regulatory approval to expand its operations to Franklin County in New York State. The construction associated with the expansion began in August 2012 and the completion of the high pressure distribution line is expected late in the first quarter of 2015. The total capital cost through 2018, including several distribution systems, is estimated to be US$52 million, with expenditures to date of approximately US$48 million. The expansion is expected to add 4,400 potential customers to St. Lawrence's distribution system, which had 16,000 customers as at December 31, 2014.

AGREEMENT WITH TRANSCANADA

In September 2013, the Company, along with Union Gas Limited and Gaz Metro Limited Partnership, announced an agreement with TransCanada Pipelines Limited intended to modify the tolling structure of TransCanada's Mainline system. In December 2014 the National Energy Board substantially approved the terms of the agreement through its approval of TransCanada's 2015 to 2020 Mainline toll application. The resulting toll and tolling structure changes are expected to support new infrastructure investments needed to enhance longer term energy cost competitiveness for eastern Canadian markets by providing improved access to diverse and affordable natural gas supplies.

PRECEDENT AGREEMENTS FOR LONG-TERM TRANSPORTATION CAPACITY

In January 2013, the Company signed a precedent agreement and a financial backstopping agreement for pipeline transportation capacity from the Dawn trading hub to Parkway (GTA). The transportation agreement will have a 15-year term and is targeted to start in November 2015 to coincide with the completion of the GTA Project. The additional capacity is needed to allow the change in flows on the Company's distribution system and take advantage of the additional capacity from the GTA Project facilities.

In June 2014, the Company signed a precedent agreement and a financial assurances agreement for pipeline transportation capacity from Niagara/Chippewa to the Company's franchise in the GTA. The transportation agreement will have a 15-year term and is targeted to start in November 2015 to coincide with the completion of the GTA Project.

In July 2014, the Company signed precedent agreements and financial backstopping agreements for pipeline transportation capacity from the Dawn trading hub to the Enbridge Eastern Delivery Area (Ottawa Region). The transportation agreements will have 15-year terms and are targeted to start in November 2016. The agreements are required to meet approximately 25% of peak day demand in the Ottawa Region as a result of a decision by TransCanada to declare certain existing capacity as reserved for the Energy East Project and therefore non-renewable by gas shippers past October 2016. The agreements will allow greater access to the Dawn trading hub and other supply options upstream of Dawn for the Ottawa region of the Company's franchise area.

In December 2014, the Company signed a precedent agreement with the proponents of the NEXUS Gas Transmission pipeline to acquire pipeline transportation capacity from Kensington, Ohio to Vector Pipeline L. P.'s Milford Junction metering station near Highland, Michigan. The transportation agreement will have a 15-year term with a targeted pipeline in-service date of November 1, 2017. This pipeline transportation capacity will provide improved access to natural gas from the Utica and Marcellus production basins. The obligations of this agreement are contingent on OEB regulatory approval in a form acceptable to the Company.

RESULTS OF OPERATIONS

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Gas distribution margin[1]	**1,062**	1,069	985
Other revenue	**92**	97	202
Operating and administrative expenses	**(493)**	(496)	(489)
Depreciation and amortization	**(286)**	(304)	(320)
Earnings sharing	**(12)**	-	(10)
Other income	**66**	65	63
Interest expense, net	**(177)**	(171)	(170)
Income taxes	**(6)**	(43)	(53)
Earnings from continuing operations	**246**	217	208
Earnings from discontinued operations, net of tax	**-**	-	4
Earnings	**246**	217	212
Earnings attributable to the common shareholder	**244**	215	210

1 *For more information on this non-GAAP measure see page 5.*

GAS DISTRIBUTION MARGIN

Gas distribution margin for the year ended December 31, 2014 decreased by $7 million compared with the year ended December 31, 2013. The decrease was primarily due to lower distribution rates partially offset by colder weather and customer growth.

The heating degree days reported in 2014 were 527 heating degree days colder compared with forecast heating degree days. On a weather-normalized basis, net gas distribution margin for the year ended December 31, 2014 would have been lower by $48 million (2013 - lower by $13 million). Weather, measured in heating degree days, was 4,044 heating degree days for the year ended December 31, 2014 compared with 3,746 heating degree days for the year ended December 31, 2013.

Gas distribution margin for the year ended December 31, 2013 increased by $84 million compared with the year ended December 31, 2012. The increase was primarily due to colder weather and customer growth.

The heating degree days reported in 2013 were 78 heating degree days colder compared with forecast heating degree days. On a weather-normalized basis, net gas distribution margin for the year ended December 31, 2013 would have been lower by $13 million (2012 - higher by $31 million). Weather, measured in heating degree days, was 3,746 heating degree days for the year ended December 31, 2013 compared with 3,194 heating degree days for the year ended December 31, 2012.

OTHER REVENUE

Other revenue for the year ended December 31, 2014 decreased by $5 million compared with the year ended December 31, 2013. The decrease was primarily due to lower DSMIDA revenue partially offset by higher late payment penalties, higher oil revenue, and adjustments to reflect developments in the 2012 ESM regulatory proceedings in the prior year.

Other revenue for the year ended December 31, 2013 decreased by $105 million compared with the year ended December 31, 2012. The decrease was primarily due to the recognition of an OPEB regulatory asset in the prior year, adjustments to reflect developments in the 2012 ESM regulatory proceedings, lower oil revenue and lower revenue from the management of fee-for-service energy efficiency initiatives. This was partially offset by higher DSMIDA revenue.

OPERATING AND ADMINISTRATIVE

Operating and administrative expenses for the year ended December 31, 2014 decreased by $3 million compared with the year ended December 31, 2013. The decrease was primarily due to lower employee and other related costs, partially offset by higher customer support and amortization of regulatory liabilities.

Operating and administrative expenses for the year ended December 31, 2013 increased by $7 million compared with the year ended December 31, 2012. The increase was primarily due to higher pension costs and higher operational, system integrity and safety costs, partially offset by lower customer support related costs.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the year ended December 31, 2014 decreased by $18 million compared with the year ended December 31, 2013. The decrease primarily resulted from the adoption of the new approach for determining net negative salvage percentages, partially offset by an increase in the overall asset base. Additional information about the impact of the revised rates is included in Note 3 of the 2014 Annual Consolidated Financial Statements.

Depreciation and amortization expense for the year ended December 31, 2013 decreased by $16 million compared with the year ended December 31, 2012. The decrease primarily resulted from the application of new depreciation rates which came into effect on January 1, 2013, pursuant to a depreciation study commissioned by the Company in 2012. The revised rates formed part of the 2013 Settlement. This was partially offset by an increase in the overall asset base resulting from improvements to the distribution system and customer growth projects.

EARNINGS SHARING

Under the customized IR plan in 2014, earnings sharing represents the estimated customer portion of regulated normalized earnings in excess of the approved ROE threshold applicable to the Company. Earnings sharing is management’s best estimate of the proportionate earnings sharing with reference to earnings for the full year. The ESM will result in the return in revenue of $12 million to customers for the year ended December 31, 2014, subject to OEB approval. Earnings sharing did not apply to the 2013 rate year.

Under IR in 2012, earnings sharing represented the estimated customer portion of regulated earnings in excess of 100 basis points above the allowed utility ROE threshold applicable to the Company. The allowed ROE was developed through the approved IR formula for the 2012 fiscal year and relating to the OEB’s ROE policy guideline in effect prior to December 2009.

INTEREST EXPENSE

Interest expense, net, for the year ended December 31, 2014 increased by $6 million compared with the year ended December 31, 2013. The increase was primarily due to the issuance of medium-term notes (MTNs) in 2014, and additional draws on the credit facilities at a higher interest rate. This was partially offset by interest on regulatory deferrals.

Interest expense, net, for the year ended December 31, 2013 increased by $1 million compared with the year ended December 31, 2012. The increase was primarily due to the issuance of MTNs in 2013 and interest on higher regulatory liabilities.

INCOME TAXES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**252**	260	261
Income taxes	**6**	43	53
Effective tax rate (%)	**2.4**	16.5	20.3

The effective tax rate for the year ended December 31, 2014 was lower compared with the year ended December 31, 2013. The decrease was due to the refund to customers of previously collected site restoration costs, temporary differences relating to regulatory property, plant and equipment and intangible assets, and lower pre-tax earnings.

The effective tax rate for the year ended December 31, 2013 was lower compared with the year ended December 31, 2012. The decrease was due to a revaluation of the deferred tax liabilities in the prior year as a result of an increase in the Ontario income tax rate in 2012 and a capital gain from the sale of Project Amherstburg in 2012. The decrease was partially offset by temporary differences relating to regulatory property, plant and equipment and intangible assets.

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).

Pursuant to a November 2013 OEB interim rate order, the Company continued to apply 2013 rates in 2014 until a final rate order for 2014 rates was issued by the OEB, within the Company's customized IR rate proceeding. The OEB's August 2014 Decision and Rate Order approved final 2014 rates, which were implemented on October 1, 2014, but effective January 1, 2014.

For the year ended December 31, 2013, the Company's rates were set on a cost of service basis pursuant to the 2013 Settlement. For the year ended December 31, 2012, the Company's rates were set using a revenue per customer cap IR methodology, which was in place from 2008 through 2012. The IR methodology adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions. St. Lawrence's rates were set on a cost of service basis for the years ended December 31, 2014, 2013 and 2012.

IMPACT OF RATE REGULATION

The Company follows U.S. 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 Standards Codification 980 (ASC 980), *Regulated Operations*, 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 4 to the 2014 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. Cost of gas, 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 approved 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 current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

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 April 2014, the Company issued $300 million of three-year medium-term notes at an interest rate of 1.85%. In June 2014, a new $1,000 million shelf prospectus was filed as a continuation of the Company's medium-term note program, which was last renewed in January 2013. The prospectus is effective for a 25-month period. In August 2014, the Company issued $215 million of ten-year medium-term notes at an interest rate of 3.15% and $215 million of thirty-year medium-term notes at an interest rate of 4.00%.

In June 2014, the Company obtained a new $300 million revolving credit facility from Enbridge Inc. which has a term out date in June 2015 and a maturity date in June 2016. As at December 31, 2014, $175 million was drawn on this credit facility. The Company also increased its external credit facility by $300 million to a total of $1,000 million and extended the term out date for an additional year to July 2015, with a maturity date in July 2016.

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, 2014.

				December 31, 2014	December 31, 2013
	Maturity dates	Total Facilities[1]	Draws[2]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2016	**1,300**	**1,110**	**190**	700
St. Lawrence Gas Company, Inc.	2019	**8**	**8**	**-**	13
Total credit facilities		**1,308**	**1,118**	**190**	713

1 *Includes a $300 million revolving credit facility from the Company's parent, Enbridge Inc.*
2 *Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility.*

In addition to the committed credit facilities noted above, St. Lawrence Gas Company, Inc. also has $6 million (2013 - $5 million) of uncommitted demand credit facilities, of which $2 million (2013 - $1 million) was unutilized as at December 31, 2014.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and draws bear interest at market rates.

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,	**2014**	2013
(millions of Canadian dollars)		
Cash and cash equivalents	**35**	44
Accounts receivable and other	**1,189**	706
Gas inventories	**563**	382
Bank indebtedness	**(9)**	(4)
Short-term borrowings	**(938)**	(374)
Short-term borrowings from affiliates	**(204)**	(15)
Accounts payable and other	**(974)**	(769)
Working capital	**(338)**	(30)

Despite the negative working capital, excluding the current portion of long-term debt, as at December 31, 2014, the Company has net available liquidity through access to funds from committed credit facilities, issuance of medium-term notes in the Canadian public capital markets through the Company's current shelf prospectus, and, if necessary, additional liquidity is available through related party transactions with Enbridge Inc. or other related entities. At December 31, 2014 the net available liquidity totaled $216 million.

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, 2014, this ratio was 2.32 (2013 - 2.40). 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 used by operating activities was $414 million for the year ended December 31, 2014 compared with cash provided of $450 million in 2013. The increase in cash used was primarily due to the OEB decision issued in May 2014 allowing a portion of the PGVA balance as of June 2014 to be recovered from customers over a 24-month period from July 2014 to June 2016 as compared to the 12-month period PGVA has historically been collected over. The December 31, 2014 PGVA balance was higher primarily due to significantly higher natural gas prices, combined with colder weather during the first quarter of 2014. In addition, as of December 31, 2014 there was a higher gas inventories balance due to the Company maintaining higher gas inventories in anticipation of the upcoming winter season.

Cash provided by operating activities was $450 million for the year ended December 31, 2013 compared with $555 million in 2012. The decrease in cash provided was primarily due to fluctuations in working capital resulting from the impacts of weather and natural gas prices. The cash outflows within operating activities were partially offset by proceeds on the settlement of certain derivative instruments related to the MTNs issued in 2013.

INVESTING ACTIVITIES

Cash used for investing activities was $626 million for the year ended December 31, 2014 compared with $547 million in 2013. The increase in cash used was primarily due to higher comparative capital spending on the GTA Project and technology related projects.

Cash used for investing activities was $547 million for the year ended December 31, 2013 compared with $391 million in 2012. The increase in cash used was primarily due to higher comparative capital spending on improvements to the distribution system and customer growth projects.

CAPITAL EXPENDITURES

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
System improvements and upgrades	**371**	298	199
System expansion	**165**	167	157
Computers and communication equipment	**44**	39	43
Unregulated storage	**1**	1	1
Other	**82**	81	79
Total capital expenditures	**663**	586	479

The Company's existing distribution network consists of approximately 37,600 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 $1.0 billion in 2015 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $527 million.

Major 2015 capital projects include the GTA Project and a Work Asset Management Solution program. The net planned liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently approved capital projects and to provide flexibility for new investment opportunities.

FINANCING ACTIVITIES

Cash provided by financing activities was $1,031 million for the year ended December 31, 2014 compared with $138 million in 2013. The increase in cash provided primarily resulted from the issuance of the term notes and short-term borrowings, partially offset by term note repayments.

Cash provided by financing activities was $138 million for the year ended December 31, 2013 compared with cash used of $170 million in 2012. The increase in cash provided was primarily due to the issuance of MTNs and common shares during the year, partially offset by higher net repayments of short-term borrowings.

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

PREFERENCE SHARES

Floating adjustable cumulative cash dividends on the Group 3, Series D preference 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 preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2014, no preference shares have been redeemed.

On July 1, 2019, and every five years thereafter, the Group 3, Series D preference shares can be converted, at the holder's option, into Group 2, Series D preference shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period. The Group 3, Series D preference shareholders opted not to convert their shares into Group 2, Series D preference shares effective July 1, 2014.

The Group 2, Series D preference shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preference shares can also be converted into Group 3, Series D preference shares on a one-for-one basis at the holder's option on July 1, 2019 and every five years thereafter.

Outstanding Share Data[1]

	Number
Preference Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common shares	158,984,050

1. Outstanding share data information is provided as at February 18, 2015.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2013 and December 31, 2014.

Consolidated Statements of Financial Position Category	Increase	Explanation
(millions of Canadian dollars)		
Accounts receivable and other	483	Primarily due to higher natural gas costs to be recovered from customers through the PGVA within the next 12 months.
Gas inventories	181	Primarily due to higher natural gas prices and higher volumes in storage.
Property, plant and equipment, net	399	Primarily due to capital additions relating to the GTA Project and technology related projects, partially offset by depreciation.
Deferred amounts and other assets	359	Primarily due to higher natural gas costs to be recovered from customers through the PGVA beyond the next 12-month period, recording of a regulatory asset for constant dollar new salvage adjustment per an OEB rate order, and an increase in deferred taxes related to regulated assets.
Short-term borrowings (including amounts from affiliates)	753	Primarily to fund working capital needs.
Accounts payable and other	205	Primarily due to regulatory balances owing to customers within the next 12 months relating to site restoration, revenue refund and earnings sharing.
Long-term debt (including current portion)	328	Increased due to the issuance of MTNs, partially offset by the repayment of a current portion of long-term debt.
Common shares	150	Due to a common share issuance during the year.

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, certain volumetric imbalances typically result whereby the Company either holds natural gas on behalf of transportation service customers or such customers have consumed more natural gas than the amount delivered to the Company. Specific defined parameters are in place and are monitored carefully to ensure that the volume of such imbalances does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All volume imbalances are trued up annually. The Company also has strict credit policies in place to mitigate this risk.

Included in, or deducted from, physical 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.

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 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 the required steps in the discovery process were not completed by the plaintiff. The Company has brought a motion to dismiss the plaintiff's action for delay. At present, it is unknown when or if 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 2014 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

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

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

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]	3,118	2	503	3	2,610
Gas transportation and storage contracts[2]	4,415	1,307	1,334	700	1,074
Loans from affiliate company[1]	375	-	-	-	375
Customer care service contracts[3]	278	53	110	115	-
Right-of-way commitments[4]	130	2	4	4	120
Capital commitments	505	419	45	28	13
Operating leases	9	4	5	-	-
Pension obligations[5]	4	4	-	-	-
Total contractual obligations	8,834	1,791	2,001	850	4,192

1. *Excludes interest, discounts and premiums. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*
2. *Includes the precedent agreements for long-term transportation capacity that were signed in January 2013, June 2014, and July 2014.*
3. *In 2014, the Company's Board of Directors approved a two-year extension, beginning in 2018, 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 $113 million.*
4. *Right-of-way payments are estimated to be approximately $2 million per year for the remaining life of all storage reservoirs, which has been assumed to be 60 years for purposes of calculating the amount of future minimum commitments beyond 2018.*
5. *Assumes only required payments will be made into the pension plans. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2013. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

QUARTERLY FINANCIAL INFORMATION

2014[1]	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
(millions of Canadian dollars)					
Revenues	**1,238**	**672**	**362**	**928**	**3,200**
Earnings attributable to the common shareholder	**138**	**29**	**5**	**72**	**244**
(Colder)/warmer than normal weather (after-tax impact)	**(33)**	**(4)**	**2**	**(1)**	**(36)**

2013[1]	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars)					
Revenues	1,027	472	335	814	2,648
Earnings attributable to the common shareholder	98	31	1	85	215
Warmer/(colder) than normal weather (after-tax impact)	6	(2)	-	(13)	(9)

1. *Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. 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 2014 HIGHLIGHTS

Earnings attributable to the common shareholder were $72 million for the three months ended December 31, 2014 compared with $85 million for the same period in 2013. The decrease was primarily due to warmer weather during the fourth quarter of 2014 compared to 2013, partially offset by higher after-tax rate of return on common equity.

Earnings attributable to the common shareholder were $85 million for the three months ended December 31, 2013 compared with $121 million for the same period in 2012. The decrease primarily resulted from lower other revenue due to the recognition of an OPEB regulatory asset in the fourth quarter of 2012, partially offset by colder weather and higher DSMIDA revenue.

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 preference shares of IPL System Inc., an affiliated company under common control. At December 31, 2014, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2014, dividends received amounted to $63 million (2013 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2014 (2013 - $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 preference shares of the Company. For the year ended December 31, 2014, interest paid amounted to $27 million (2013 - $27 million) with an outstanding payable balance of $2 million at December 31, 2014 (2013 - $2 million).

Enbridge (U.S.), an affiliated company under common control, advanced St. Lawrence $29 million (2013 - $15 million) at the LIBOR rate plus 0.55%, payable on demand.

Enbridge Inc., 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, 2014 were $41 million (2013 - $38 million) with an outstanding payable balance of $7 million at December 31, 2014 (2013 - $5 million).

Enbridge Inc., established a $300 million revolving credit facility with the Company in June 2014, which has a term out date in June 2015 and a maturity date in June 2016. For the year ended December 31, 2014, $175 million (2013 - nil) was drawn, and interest paid amounted to $2 million (2013 - nil) with an outstanding payable balance of nil at December 31, 2014 (2013 - nil).

Tidal Energy Marketing Inc., an affiliated company under common control, sells natural gas to the Company at prevailing market prices and under normal trade terms. Total charges for the year ended December 31, 2014 were $41 million (2013 - $30 million) with an outstanding payable balance of $3 million at December 31, 2014 (2013 - $7 million).

Tidal Energy Marketing (U.S.) LLC, an affiliated company under common control, sells natural gas to the Company at prevailing market prices and under normal trade terms. Total charges for the year ended December 31, 2014 were $57 million (2013 - $21 million) with an outstanding payable balance of $3 million at December 31, 2014 (2013 - $4 million).

Aux Sable Canada LP, a related entity partially owned by an affiliated company under common control, sells natural gas to the Company at prevailing market prices under normal trade terms. Total charges for the year ended December 31, 2014 were $16 million (2013 - nil) with an outstanding payable of $8 million at December 31, 2014 (2013 - nil).

Gazifère Inc., an affiliated company under common control, obtains gas procurement and transportation 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, 2014 were $31 million (2013 - $30 million) with an outstanding receivable of $6 million at December 31, 2014 (2013 - $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, 2014 were $27 million (2013 - $24 million) with an outstanding payable of $2 million at December 31, 2014 (2013 - $2 million).

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, 2014 were $2 million (2013 - $2 million) with an outstanding payable of nil at December 31, 2014 (2013 - 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, 2014 were $26 million (2013 - $26 million) with an outstanding payable of $2 million at December 31, 2014 (2013 - $2 million).

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, 2014 were $20 million (2013 - $19 million) with an outstanding payable of $2 million at December 31, 2014 (2013 - $2 million).

Other Transactions

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. At December 31, 2014, the Company had an outstanding payable of $15 million to Enbridge Pipelines Inc. (2013 - $15 million receivable) and an outstanding payable of nil to IPL System Inc. (2013 - $15 million).

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund, an affiliated entity under common control, for cash proceeds of $72 million.

RISK FACTORS

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.

In 2014, the Company's rates were approved by the OEB as part of the Decision and Rate Order received by the Company in its customized IR application. The OEB approved the ROE that the Company is permitted to charge in rates within the customized IR model, in addition to various other cost projections in relation to the utility's operations. The OEB approved ROE is based on the OEB's Cost of Capital guidelines as applicable to the Company. The Company is also permitted by the OEB to recover costs considered within the scope of various deferral and variance accounts in relation to items for which costs cannot be accurately forecast. To the extent that costs fall outside of those approved by the OEB within rates and permitted within the scope of approved deferral and variance accounts, the Company is at risk.

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 revenue depends in large part on achieving the forecast distribution volume established in the rate-making process. Volume forecasts are reviewed and approved by the OEB annually.

Variations in volumetric consumption depend on four key variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers.

Weather is a significant driver of delivery volumes, given that a significant portion of the Company's customer base uses natural gas for space heating. Weather, measured in terms of heating degree days, can have a direct impact on 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	1.4 billion cubic feet
Volume	1 billion cubic feet	$1 million (after-tax)

An unusual distribution pattern of heating degree days during the year may impact the sensitivity described above. 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 increased adoption of energy efficient technologies, including more efficient building construction. In addition, conservation efforts by customers can further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 81% (2013 - 81%) 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.

There may be circumstances where the Company attains its total forecast distribution volume, but revenues are different from forecast as a result of other variables such as the mix between the residential, commercial and industrial sectors.

The Company remains at risk for the actual versus forecast large volume contract commercial and industrial volumes; however, general service volume risk is mitigated for both ratepayers and the Company through the average use true-up variance account. This variance account records the difference between forecast and actual weather normalized general service average uses, and trues up for the difference, through either a collection or repayment to customers. All parties are kept whole to the weather normalized general service volumetric forecast.

MARKET RISK

The Company’s earnings, cash flows and Other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, and natural gas prices (collectively, market 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 risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses qualifying derivative instruments to manage some of the risks noted below.

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 in the exchange rate 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.

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. Pay fixed-receive floating interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense incurred on variable rate debt.

The Company’s earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company’s exposure to long-term interest rate variability on select forecast term debt issuances.

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. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil.

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2014**	2013	2012
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(84)**	109	(1)
	(84)	109	(1)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**-**	(2)	(2)
	-	(2)	(2)
Amount of gain reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**-**	2	-
	-	2	-

1. Reported within Interest expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper, draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes, and, if necessary, additional liquidity is available through intercompany transactions with Enbridge Inc. and other related entities. These sources are expected to be sufficient to enable the Company to fund all anticipated requirements. The Company maintains a current shelf prospectus with securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition to the Company's access to the Canadian public capital markets, the Company maintains committed credit facilities with a diversified group of banks and institutions. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2014. 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.

CREDIT RISK

Exposure to credit risk is 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 with regard 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 credit concentration with any single counterparty.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. 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 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 approximates 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.

The Company's investment in IPL System Inc., an affiliate company, is recorded at fair value. At December 31, 2014 the fair value of the investment was $825 million (2013 - $825 million), which approximates its cost and redemption value. At December 31, 2014, the Company's long-term debt had a carrying value of $3,127 million (2013 - $2,799 million) and a fair value of $3,709 million (2013 - $3,161 million).

Additional information about the Company's risk management and financial instruments is included in Note 16 of the 2014 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

Upstream Supply or Transport Failure

The Company's ability to deliver natural gas to its customers on demand is dependent on adequate supply being transported on third party transmission pipelines to its franchise. While the Company has received reliable service from its upstream service providers, a large supply or pipeline disruption on a very cold day has the potential to cause service disruption. The Company procures supply and transport from third party suppliers and pipelines to meet design winter conditions as approved by its regulator and diversifies its procurement to the extent possible.

Network Operating Risk

The Company's network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, malfunction of compression, regulation and measurement equipment and other issues that can lead to unplanned natural gas escapes and outages. Leaks in the distribution system are an inherent risk of operations. Surveillance, maintenance and repair programs as well as the phased replacement of targeted pipes significantly reduces the exposure. In 2012, the Company completed its cast iron replacement and bare steel main replacement program.

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 extensive programs to manage pipeline integrity, which include leak survey, corrosion survey and the use of in-line inspection tools for high stress pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as the need is identified. The Company also maintains comprehensive insurance coverage for significant pipeline events and has a 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 participates in a comprehensive insurance program which is maintained by Enbridge for its subsidiaries and affiliates. The program includes commercial liability insurance coverage and coverage for environmental incidents, taking into account coverage levels considered customary for its industry and the insurance market at the time of renewal. In the unlikely event multiple insurable incidents exceeding coverage limits are experienced by Enbridge subsidiaries or affiliates within the same insurance period, the total insurance coverage will be allocated on an equitable basis.

Public, Worker and Contractor Safety
Several of the Company's pipeline systems run adjacent to populated areas and a major incident could result in injury to members of the public. A public safety incident could result in reputational damage to the Company, material repair costs or increased costs of operating and insuring the Company's assets. In addition, given the natural hazards inherent in the Company's operations, its workers and contractors are often subject to personal safety risks.

Safety and operational reliability are the most important priorities at the Company. The Company's mitigation efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its strategic plan and emergency response preparedness. The Company also actively engages stakeholders through public safety awareness activities to ensure the public is aware of potential hazards and understands the appropriate actions to take in the event of an emergency. The Company also actively engages first responders through education programs that endeavour to equip first responders with the skills and tools to safely and effectively respond to a potential incident.

Finally, the Company believes in a safety culture where safety incidents are not tolerated by employees and contractors and has established a target of zero incidents. For employees, safety objectives have been incorporated across all levels of the Company, and included as part of an employee's compensation measures. Contractors are chosen following a rigorous selection process that includes a strict adherence to the Company's safety culture.

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 continue to develop. It is currently unclear how natural gas distributors will be specifically treated.

Ontario is a signatory to the Western Climate Initiative. Ontario is currently developing a carbon management strategy which will be released in 2015. The Company reports GHG emissions from combustion sources only in Ontario, and all reported data is verified by a third party. There were no issues identified for the 2014 reporting year. The Company continues to monitor developments and attend stakeholder consultations in Ontario.

The Company has successfully deployed a carbon data management system to help with the data capture and mandatory and voluntary reporting needs of the Company. The Company continues to publicly report its GHG emissions and will continue to develop internal procedures to identify operationally related GHG reductions.

Public Opinion
Public opinion or 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, special interest groups, political leadership, the media or other entities. Potential impacts of a negative public opinion may include loss of business, delays in project execution, legal action, increased regulatory oversight or delays in regulatory approval and higher costs.

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 health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations with an emphasis on the prevention of any incidents;
- 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 strong corporate governance practices, including a Statement on Business Conduct, with which requires all employees 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).

The Company's actions noted above are the key mitigation action against negative public opinion; however, the public opinion risk can not be mitigated solely by the Company's individual actions. The Company actively works with other stakeholders in the industry to collaborate and work closely with government and Aboriginal communities to enhance the public opinion of the Company, as well as the industry in which it operates.

Information Technology Security or Systems Incident
The Company's infrastructure, applications and data are becoming more integrated, creating an increased risk a failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activity targeting industrial control systems. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems. A successful cyber-attack could also lead to a large scale data breach resulting in unauthorized disclosure, corruption or loss of sensitive company or customer information. The Company's comprehensive security strategy focuses on information technology security risk management, strong governance, layered access controls, continuous monitoring, infrastructure and network security, round-the-clock threat detection and incident response. The Company's information technology security operations are consolidated under one leadership structure to increase consistency and compliance with the Company's security requirements.

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, 2014 of $6,268 million (2013 - $5,869 million), or 64% of total assets (2013 - 70%), 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 2013. 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 U.S. 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, 2014, the Company's regulatory assets totaled $1,278 million (2013 - $366 million) and regulatory liabilities totaled $973 million (2013 - $992 million). To the extent that the Regulators' future actions differ from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POSTRETIREMENT 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 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.

The difference between the actual and expected return on plan assets was an excess of $37 million for the year ended December 31, 2014 (2013 - excess of $32 million) as disclosed in Note 18 to the 2014

Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension plans, contribution in 2015 will be $4 million.

The following sensitivity analysis identifies the impact on the December 31, 2014 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	79	6	8	-
Decrease in expected return on assets	-	4	n/a	n/a
Decrease in rate of salary increase	(12)	(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 2014 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 was also 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

United States Generally Accepted Accounting Principles
The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada.

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements
Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Extraordinary and Unusual Items
ASU 2015-01 was issued in January 2015 and eliminates the concept of extraordinary items from GAAP. Entities will no longer be required to separately classify and present extraordinary events in the income statement, net of tax, after income from continuing operations. This accounting update is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied prospectively or retrospectively. The adoption of the pronouncement is not anticipated to have an impact on the consolidated financial statements.

Revenue from Contracts with Customers
ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
ASU 2014-8 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively. The adoption of the pronouncement is not anticipated to have an impact on the Company's consolidated financial statements.

CHANGES IN ACCOUNTING ESTIMATES

Depreciation Rates
In 2014, the Company revised depreciation rates based on the results of a new net negative salvage study which was approved by the Ontario Energy Board (OEB) as part of the 2014 to 2018 customized incentive regulation (IR) plan. The revised rates decreased depreciation and amortization expense by $44 million for the year ended December 31, 2014.

HIGHLIGHTS

Year ended December 31,	**2014**	2013
Financial *(millions of Canadian dollars)*		
Gas commodity and distribution revenue	**2,803**	2,221
Transportation of gas for customers	**305**	328
Other revenue	**92**	97
Total revenue from continuing operations	**3,200**	2,646
Gas commodity and distribution costs excluding depreciation	**(2,046)**	(1,480)
	1,154	1,166
Earnings	**246**	217
Earnings attributable to the common shareholder	**244**	215
Return on equity[1] (%)	**9.4**	9.0
Operating		
Volumetric statistics *(millions of cubic metres)*		
Gas commodity sales	**8,209**	7,365
Transportation of gas for customers	**4,462**	4,553
Unbundled volumes[2]	**382**	378
Total volume	**13,053**	12,296
Number of active customers[3] *(thousands)*	**2,098**	2,065
Heating degree days[4]		
Actual	**4,044**	3,746
Forecast based on normal weather	**3,517**	3,668

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 GTA.*