Trina Wright
Regulatory Coordinator
Regulatory Affairs

tel 416 495 5173
trina.wright@enbridge.com

Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
Canada

April 20, 2016

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")
2015 Earnings Sharing Mechanism and Other Deferral And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2016-0142

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 2015 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)

Trina Wright
Regulatory Coordinator

cc: Mr. D. Stevens, Aird & Berlis LLP
All Interested Parties EB-2015-0114 (via email)

EXHIBIT LIST

A – ADMINISTRATIVE

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

B – 2015 ACTUAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	2015 Earnings Sharing Amount and Determination Process	R. Small
		2	ESM Calculations and Required Rate of Return 2015 Actuals	R. Small
		3	2015 Utility Earnings – Contributors to Utility Earnings and Earnings Sharing Amounts	R. Small
		4	Utility Earnings – Reconciliation of 2015 Utility Income to Audited EGDI Consolidated Income	R. Small
	2	1	Ontario Utility Rate Base – Comparison of 2015 Actuals to 2015 EB-2014-0276 Board Approved	R. Small
		2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2015 Actuals	R. Small

EXHIBIT LIST

B – 2015 ACTUAL YEAR & EARNINGS SHARING RESULTS

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, 2016	R. Small
		2	2015 Unabsorbed Demand Cost Deferral Account explanation	J. LeBlanc D. Small
		3	2015 Storage & Transportation Deferral Account and 2015 Transactional Services Deferral Account	J. LeBlanc D. Small
		4	2015 Unaccounted For Variance Account Explanation	R. Cheung C. Ho
		5	2015 Actual Average Use True Up Variance Account Explanation	R. Cheung C. Ho
		6	2015 Post Retirement True Up Variance Account Explanation	J. Barradas J. Shem
		7	2015 Gas Distribution Access Rule Impact Deferral Account	D. McIlwraith R. Small
		8	2015 Deferred Rebate Account	R. Small
		9	2016 Transition Impact of Accounting Changes Deferral Account	R. Small J. Barradas
		10	2015 Customer Care CIS Rate Smoothing Deferral Account	D. McIlwraith R. Small
		11	2015 Electric Program Earnings Sharing Deferral Account	E. Reimer
		12	2015 Energy East Consultation Costs Deferral Account	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 B. So
		2	Derivation of Proposed Unit Rates	J. Collier A. Kacicnik B. So

D – REPORTING AND REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	1	1	Status Updates	N. Verma
		2	Status of GTA Project	S. Dodd
		3	Status of WAMS Project	W. Akkermans B. Misra
		4	Status of System Integrity Program	D. Broude
		5	Status of Benchmarking Study	L. Lawler H. Sayyan
		6	Status of Asset Management Planning Process	T. MacLean
	2	1	Productivity Initiatives Summary	L. Lawler M. Yan
	3	1	March 30, 2016 Stakeholder Day Presentation	N. Verma

EXHIBIT LIST

D – REPORTING AND REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	4	1	2016 Gas Supply Memorandum	D. Small A. Welburn
	5	1	2015 RRR filings re. Service Quality Indicators	K. Lakatos-Hayward L. Parrington
	6	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2015	J. Barradas
		2	Enbridge Gas Distribution Inc. Management's Discussion & Analysis – December 31, 2015	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.

APPLICATION

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

2. Enbridge hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 36 of the *Ontario Energy Board Act, 1998* (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 2015 ESMDA, as well as the balances within certain of its 2015 Deferral and Variance accounts and 2014 DSM-related accounts and the 2016 TIACDA, 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 2015 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, 2016 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: April 20, 2016 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: Original Signed

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

			Col. 1	Col. 2	Col. 3	Col. 4	
			Actual at March 31, 2016		Forecast for clearance at October 1, 2016		
Line No.	Account Description	Account Acronym	Principal ($000's)	Interest ($000's)	Principal ($000's)	Interest ($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2014 DSMVA	352.5	5.2	352.5	7.0	1
2.	Demand Side Management V/A	2015 DSMVA	1,391.4	3.8	-	-	2
3.	Lost Revenue Adjustment Mechanism	2014 LRAM	(65.3)	(0.2)	(65.3)	(0.8)	1
4.	Demand Side Management Incentive D/A	2014 DSMIDA	7,647.2	28.0	7,647.2	70.0	1
5.	Deferred Rebate Account	2015 DRA	419.0	0.4	419.0	2.8	3
6.	Manufactured Gas Plant D/A	2016 MGPDA	537.7	35.0	-	-	4
7.	Electric Program Earnings Sharing D/A	2015 EPESDA	(59.3)	(0.2)	(59.3)	(0.8)	5
8.	Gas Distribution Access Rule Impact D/A	2015 GDARIDA	-	-	295.2	-	6
9.	Average Use True-Up V/A	2015 AUTUVA	(2,278.3)	(6.3)	(2,278.3)	(18.9)	7
10.	Earnings Sharing Mechanism Deferral Account	2015 ESMDA	(6,450.0)	(17.7)	(6,450.0)	(53.1)	8
11.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	11.7	-	20.1	9
12.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	21.5	-	43.1	9
13.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	34.1	-	68.1	9
14.	Transition Impact of Accounting Changes D/A	2016 TIACDA	75,408.6	-	4,435.8	-	10
15.	Post-Retirement True-Up V/A	2015 PTUVA	(880.1)	(17.0)	(880.1)	(21.8)	11
16.	Constant Dollar Net Salvage Adjustment D/A	2016 CDNSADA	42,042.2	-	-	-	12
17.	Energy East Consultation Costs D/A	2015 EECCDA	157.5	0.7	157.5	1.3	13
18.	Greenhouse Gas Emissions Impact D/A	2016 GGEIDA	127.5	0.4	-	-	14
19.	Total non commodity Related Accounts		127,036.7	99.4	3,574.2	117.0	
	Commodity Related Accounts						
20.	Transactional Services D/A	2015 TSDA	(9,074.8)	(74.9)	(9,074.8)	(124.7)	15
21.	Storage and Transportation D/A	2015 S&TDA	4,771.4	46.0	4,771.4	72.4	15
22.	Unaccounted for Gas V/A	2015 UAFVA	1,302.9	5.2	1,302.9	12.4	16
23.	Unabsorbed Demand Cost D/A	2015 UDCDA	65,834.3	432.4	65,834.3	794.2	17
24.	Total commodity related accounts		62,833.8	408.7	62,833.8	754.3	
25.	Total Deferral and Variance Accounts		189,870.5	508.1	66,408.0	871.3	

Notes:
1. The final 2014 DSMVA, LRAM, and SSMVA balances to be cleared will be those approved within the EB-2015-0267 proceeding, which was filed October 30, 2015.
2. Clearance of the 2015 DSMVA will be requested through a separate application at a later date.
3. DRA evidence is found at Exhibit C, Tab 1, Schedule 8.
4. Clearance of the balance that was recorded in 2015 MGPDA is not being requested at this time. As was indicated in the EB-2015-0114 proceeding, the balance in the 2015 MGPDA was transferred to the 2016 MGPDA.
5. EPESDA evidence is found at Exhibit C, Tab 1, Schedule 11.
6. The clearance amount associated with the 2015 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 7.
7. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
8. Evidence within the B-series of exhibits provides details of Enbridge's 2015 utility results and 2015 earnings sharing calculation.
9. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 10.
10. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 9.
11. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 6.
12. Clearance of the balance that was recorded in 2015 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-2015-0114, the balance was transferred to the 2016 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.
13. EECCDA evidence is found at Exhibit C, Tab 1, Schedule 12.
14. Clearance of the balance that was recorded in 2015 GGEIDA is not being requested at this time. The 2015 balance of $80.3 thousand was transferred to the 2016 GGEIDA and clearance will be requested at a later date.
15. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 3.
16. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 4.
17. 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 2015 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 also includes a number of Deferral and Variance Accounts to be maintained or created during the Custom IR term. The Board has approved several other Deferral and Variance Accounts for Enbridge since the date of the Custom IR Decision with Reasons.

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: R. Small
N. Verma

6. The B-series of exhibits sets out Enbridge’s utility financial results for 2015, 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. This 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 2016 Custom IR Stakeholder Day, which was held on March 30, 2016. Other evidence includes the Company’s 2015 Productivity Initiatives Reporting, Status Updates on several major projects and initiatives, the Company’s 2015 Service Quality Indicators results, and the Company’s 2016 Gas Supply Memorandum. As was the case in Enbridge’s 2014 ESM proceeding (EB-2015-0122), Enbridge is not seeking any specific relief in this proceeding in relation to these reporting items.

9. The approvals requested in this proceeding relate to the clearance of the 2015 ESMDA and certain other Deferral and Variance Accounts.

Witnesses: R. Small
N. Verma

10. The Company has filed the balances at March 31, 2016 for fiscal year 2015 Board-approved Deferral and Variance Accounts, as well as several other Deferral and Variance Accounts from other years. The Company requests approval for clearance of certain of these accounts commencing October 1, 2016, 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 relevant balances, is provided at Appendix A to the Application (Exhibit A, Tab 2, Schedule 1, Appendix A).

11. The Company's proposal for how the Deferral and Variance Account balances will be cleared is set out at Exhibit C, Tab 2, Schedule 1. 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, Schedule 2.

12. The Company requests a Board Decision or approval by August 15, 2016, 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, 2016 QRAM proceeding.

Witnesses: R. Small
N. Verma

DRAFT ISSUES LIST

1. Is the amount proposed to be cleared in the 2015 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 (Exhibit A, Tab 2, Schedule 1, Appendix A) appropriate?

3. Are the proposed unit rates and timing for implementation of the clearances appropriate?

Witness: N. Verma

CURRICULUM VITAE OF
WILL AKKERMANS

Experience:	Enbridge Gas Distribution Inc. Director, System Operations – Operations Senior VP 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-2015-0122
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-Present

Ontario Power Generation Inc.

Director, Finance
2007-2014

Deloitte

Senior Manager, National Office
2000-2007

Bank of Montreal and Ernst & Young

Various Roles
1992-2000

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-2015-0122
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)

EB-2012-0459
RP-2004-0015 (Leave to Construct)

CURRICULUM VITAE OF
RYAN CHEUNG

Experience:	Enbridge Gas Distribution Inc.
	Advisor, Economics and Business Performance 2016
	Senior Analyst, Gas Accounting and Analytics 2014
	Senior Budget Analyst, Budget and Planning 2010
	Supervisor, Margin Planning and Analytics 2006
	Analyst, Volumetric Analysis and Budgets 2004
	TD Canada Trust
	Financial Service Advisor 2000
Education:	Bachelor of Arts, in Economic and Statistics University of Toronto
Appearances:	(Ontario Energy Board)
	EB-2012-0459 EB-2014-0195

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-2015-0114
EB-2015-0122
EB-2014-0276
EB-2013-0036
EB-2012-0459
EB-2012-0451
EB-2012-0055
EB-2011-0354
EB-2011-0277
EB-2011-0242
EB-2010-0146
EB-2009-0172
EB-2008-0219
EB-2007-0615
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-3924-2015
R-3884-2014
R-3840-2013
R-3793-2012
R-3758-2011
R-3724-2010
R-3692-2009
R-3637-2008
R-3637-2007
R-3621-2006
R-3587-2005
R-3537-2004
R-3464-2001
R-3446-2000

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
CATHERINE HO, CPA, CA

Experience:	Enbridge Gas Distribution Inc.
	Manager, Accounting 2012
	Manager, Gas Accounting 2012
	Manager, Finance Projects 2008
	Senior Audit Advisor 2005
	Ernst & Young LLP
	Senior Staff Accountant 2004
	Horwath Orenstein LLP
	Staff Accountant 2002
	Goldfarb, Shulman, Patel & Co. LLP
	Staff Accountant 2000
Education:	Chartered Accountant, 2005
	Certified Public Accountant – Delaware, 2004
	University of Waterloo – Waterloo ON • Master of Accounting (MAcc), 2003 • Bachelor of Arts Honours Chartered Accountancy Studies – Co-operative program (Dean's Honours List), 2002
Memberships:	Institute of Chartered Accountants of Ontario (ICAO)
Appearances:	(Ontario Energy Board) None

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-2015-0114
EB-2015-0122
EB-2014-0276
EB-2013-0046
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-3924-2015
R-3884-2014
R-3840-2013
R-3793-2012
R-3758-2011
R-3724-2010
R-3665-2008
R-3637-2007
R-3621-2006
R-3587-2006
R-3537-2004

CURRICULUM VITAE OF
TARA KATHLEEN KNIGHT, 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)

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

CURRICULUM VITAE OF
LISA L. LAWLER

Experience: Enbridge Gas Distribution Inc.

Director, Upstream Regulation
2016

Director, Asset & Integrity Management
2014

Director, Integrity
2010

Chief Engineer
2008

Manager, Enbridge Ontario Wind Power Project
2006

Manager, Strategic Distribution Alliance
2004

Manager, Distribution Planning
2001

Manager, Operations Eastern Region
1999

Manager, Distribution Expansion
1997

General Supervisor, Maintenance (West)
1996

Supervisor, Construction & Maintenance Administration
1995

Operations Engineer
1991

Congas Engineering Canada Limited
(a former subsidiary of The Consumers' Gas Company Ltd.)
International Marketing Engineer
1989

Education: Master of Business Administration
Wilfrid Laurier University, 1989

Bachelor of Applied Science, Chemical Engineering, Honours Program
University of Waterloo, 1988

Memberships: Professional Engineers of Ontario

Appearances: (Ontario Energy Board)

EB-2012-0459
EB-2011-0354
EB-2011-0277
EB-2009-0172
RP-2002-0133

(National Energy Board)
GHW-001-2014

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
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.
	Operating and Expenses Manager 2014
	IT and Legal Business Partner 2014
	Supervisor of Capital Management 2013
	Supervisor of Finance Operational Support 2012
	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
SUKHMINDER PURBA

Experience:	Enbridge Gas Distribution Inc.
	Manager, Financial Planning 2014
	Manager, Supply & Business Performance 2012
	Senior Budget Analyst 2010
	Senior Audit Analyst 2009
	Finance Associate 2007
	Sears Canada Inc.
	Accounting Analyst 2005
Education:	Bachelor of Administrative Studies, Specialized in Accounting York University, 2000
Memberships:	Certified Management Accountant 2009
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
ED REIMER

Experience:	Enbridge Gas Distribution Inc.
	Manager, Market Development, Strategy & Stakeholder Relationships 2014
	Manager, New Construction Energy Solutions 2012
	Manager, High Performance New Construction & Channel Sales 2009
	Manager, Key Accounts 2008
	Direct Energy Inc.
	Manager, Sales 2003
	Energy Solutions Consultant 1999
Education:	Masters of Business Administration, Niagara University, NY 1996
	Bachelor of Business Administration, Brock University, ON 1990
Memberships:	Association of Energy Service Professionals (Certified Energy Manager)
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
HULYA SAYYAN

Experience:	Enbridge Gas Distribution Inc.
	Advisor, Economic & Market Analysis 2011
	Senior Market Analyst 2007
	Risk Software Technologies
	Economic Specialist 2005
	Marmara University
	Assistant Professor, Econometrics Department 2002
	Instructor, Econometrics Department 2001
	Research Assistant, Econometrics Department 1994
Education:	Ph.D. in Econometrics Marmara University, 2000
	Master of Science in Statistics Marmara University, 1995
	Bachelor of Science in Statistics Mimar Sinan University, 1992
Memberships:	Toronto Association for Business & Economics (CABE)
Appearances:	(Ontario Energy Board)
	EB-2015-0114 EB-2014-0276 EB-2012-0459 EB-2011-0354 EB-2011-0277 EB-2010-0146

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-2015-0122 EB-2014-0276 EB-2012-0459
	(Régie de l'énergie/Régie du gaz naturel) R-3924-2015

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-2015-0114 EB-2015-0122 EB-2014-0276 EB-2013-0046 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-2015-0114
EB-2015-0049
EB-2015-0122
EB-2014-0276
EB-2014-0195
EB-2012-0459
EB-2012-0055
EB-2011-0354
EB-2011-0008

CURRICULUM VITAE OF
BRANDON SO

Experience:	Enbridge Gas Distribution Inc.
	Manager, Cost Allocation 2016
	Senior Gas Cost Accountant, Gas Accounting & Analytics 2009
	Senior Financial Analyst, Business Development & Customer Strategy 2007
	Toronto Hydro
	Senior Financial Analyst 2003
	Ballard Power Systems
	Senior Accountant 1999
Education:	Master of Business Administration Richard Ivy School of Business
	Bachelor of Business Administration (Accounting) University of Texas at Austin
	Bachelor of Arts (Economics) University of Texas at Austin
	Chartered Professional Accountant (CPA, CGA) Chartered Professional Accountants of Ontario
Memberships:	Charter Professional Accountants of Ontario
Appearances:	(Ontario Energy Board) None

CURRICULUM VITAE OF
LORI STICKLES

Experience: Enbridge Gas Distribution Inc.

Senior Manager Budgets and Financial Support
2014

Enbridge Gas New Brunswick Inc.

Manager Corporate Services
2014

Manager, Financial Reporting
2008

Staff Accountant
2004

Education: Chartered Professional Accountant
2014

Certified General Accountant
2003

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

Appearances: (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

(Ontario Energy Board)
None

CURRICULUM VITAE OF
NICK VERMA

Experience:	Enbridge Gas Distribution Inc.
	Program Manager, Regulatory Policy & Reporting 2014
	Program Manager, Operations PMO 2010
	Senior Financial Analyst, Regional Operations 2007
	Supervisor, Planning and Design 2007
	Supervisor, WMC 2005
Education:	Master of Business Administration (MBA), 2013 Wilfrid Laurier University
	Human Resource Management, 2004 York University
	Bachelor of Admin Studies, 2003 York University
Memberships:	CFA Institute Affiliate
Appearances:	(Ontario Energy Board) None

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-2015-0238 EB-2015-0175 EB-2015-0122 EB-2015-0049 EB-2014-0289
	(National Energy Board) MH-001-2013

CURRICULUM VITAE OF
MELINDA YAN

Experience: Enbridge Gas Distribution Inc.
Supervisor, Business Performance
2015

Supervisor, Internal Audit
2012

Manager, Internal Controls
2010

Accenture Inc.
Manager, Control Assurance
2008

CAA South Central Ontario
Senior Auditor
2005

Education: Chartered Professional Accountant, Certified General Accountant (CPA, CGA)
Chartered Professional Accountants of Ontario, 2014
Certified General Accountants of Ontario, 2007

Certified Fraud Examiner (CFE), Association of Certified Fraud Examiners, 2012

Certified Internal Auditor (CIA), Institute of Internal Auditors, 2010

Bachelor of Business Administration (BBA)
University of Toronto, 2003

Appearances: (Ontario Energy Board)
None

2015 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. The 2015 Earnings Sharing amount included within Enbridge Gas Distribution Inc.'s (Enbridge, or the Company) Fiscal 2015 year-end audited statements was $6.45 million, which agrees to the amount being requested for approval and clearance within this application. 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 for earnings sharing amounts calculated for 2014, and during the 2008 through 2012 incentive regulation term.

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.

Witness: R. Small

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: amounts related to Demand Side Management incentives, amounts related to Transactional Services incentives, 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.

Witness: R. Small

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.

Part A)

8. The level of utility income, $337.9 million (Line 17) divided by the level of utility rate base, $5,079.8 million (Line 22) generates a utility return on rate base of 6.652% (Line 23).

9. When compared to the Company's required rate of return of 6.465% (Line 24), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.187% (Line 25) on total rate base.

10. As shown in Lines 26 through 28, the sufficiency of 0.187% multiplied by the rate base of $5,079.8 million, produces a net over earnings or sufficiency of $9.50 million which from a pre-tax perspective, ($9.50 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%) shows a $12.92 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 $357.3 million (Line 31) of utility income before income tax, less utility taxes of $19.4 million (Line 36), produces the $337.9 million of utility income used in part A) above (at Line 17).

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) $337.9 million utility income.

14. These reductions are shown at Lines 32, 33 and 34 which along with the utility income tax reduction already mentioned and shown at Line 36, results in a net income applicable to common equity of $179.6 million, shown at Line 37.

15. The $179.6 million, divided by the deemed common equity level of $1,828.7 million (Line 38, calculated as 36% of the $5,079.8 million rate base) produces a return on equity of 9.82% (Line 40). When comparing the 9.82% achieved return on equity to the threshold ROE percentage of 9.30% (Line 39), which is the Board approved formula return on equity for 2015, there is a sufficiency in ROE of 0.52% (Line 41).

16. The 0.52% multiplied by the common equity level of $1,828.7 million (Line 38) produces a net over earnings or sufficiency of $9.49 million which from a pre-tax perspective ($9.49 million divided by the reciprocal, 73.5%, of the corporate tax rate), shows a $12.91 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 Enbridge 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, Enbridge 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 agreed in the Settlement Proposal in Enbridge’s 2016 rate adjustment proceeding (EB-2015-0114), Enbridge has included the profit from the sale of Base Pressure Gas as part of the 2015 utility earnings used to determine the 2015 ESM amount. This inclusion is without prejudice to the position that Enbridge (or any other party) may take on any similar transaction in the future.

21. 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
FOR THE YEAR ENDED DECEMBER 31, 2015

Line No.	Col. 1 Description	Col. 2 Reference	Col. 3 Actual Normalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	2,442.8
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	322.2
4.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	1.9
5.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,724.3
6.	Gas Distribution Margin		1,042.6
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	44.1
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	6.0
9.	Total - Other Revenue & Income		50.1
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)	(Ex.B,T5,S2,P1,Col.1,line 9)	430.7
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	259.7
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	3.4
13.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 12)	41.6
14.	Total O&M, Depr., & other		735.4
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	357.3
16.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	19.4
17.	**Utility Income**		**337.9**
18.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	7,586.9
19.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(2,980.8)
20.	Net plant		4,606.1
21.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 11)	473.7
22.	**Utility Rate Base**		**5,079.8**
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.652%
24.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	6.465%
25.	(Deficiency) / Sufficiency %		0.187%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	9.50
27.	Provision for Income Taxes		3.42
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	12.92
29.	**50% Earnings sharing to ratepayers**	(line 28 x 50%)	**6.46**
30.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
31.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 16)	357.3
32.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	153.9
33.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	2.2
34.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	2.2
35.	Net Income before Income Taxes		199.0
36.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	19.4
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	179.6
38.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	1,828.7
39.	Approved ROE %		9.300%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	9.819%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		0.519%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	9.49
43.	Provision for Income Taxes		3.42
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	12.91
45.	**50% Earnings sharing to ratepayers**	(line 44 x 50%)	**6.46**

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS (INCLUDING CUSTOMER CARE & CIS)
2015 ACTUAL

Line No.		Col. 1 2015 Actual Normalized $Millions	Col. 2 2015 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,442.8	2,458.9		
2.	Transportation revenue	322.2	265.3		
3.	Transmission, compression & storage (incl. Rate 332)	1.9	4.0		
4.	Gas costs	1,724.3	1,694.2		
5.	Distribution margin	1,042.6	1,034.0	8.6	a)
6.	Other revenue	44.1	42.7	1.4	b)
7.	Other income	6.0	0.1	5.9	b)
8.	O&M (incl. CC/CIS rate smoothing adj.)	430.7	431.3	0.6	c)
9.	Depreciation expense	259.7	261.7	2.0	d)
10.	Other expense	45.0	45.0	-	e)
11.	Income taxes	19.4	15.4	(4.0)	f)
12.	Utility Income	337.9	323.4	14.5	
13.	LTD & STD costs	156.1	155.4	(0.7)	g)
14.	Preference share costs	2.2	2.2	-	g)
15.	Return on Equity @ 9.30% in 2015 Board Approved	170.1	165.8	(4.3)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	9.5	0.0	9.5	
17.	Provision for taxes on Earnings Over / (Under)	3.4	0.0	3.4	
18.	Gross Earnings Over / (Under)	12.9	0.0	12.9	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	1,828.7			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	179.6			
21.	EGD normalized Return on Equity	9.82%			

Witness: R. Small

2015 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

The following are explanations of the Utility Normalized Earnings results as compared to the 2015 Board approved amounts. The reference letters are in relation to those identified on page 1 of this Schedule.

a) The distribution margin increase of $8.6 million was mainly driven by favourable Large Volume customer contract demand revenues attributable to favourable rate class migration from interruptible to firm rate classes, and lower fuel costs required to manage storage operations and the transmission of volumes on Union's system, partially offset by the impact of lower average customer unlocks and the lack of rate 332 revenues. This resulted in a positive earnings impact.

b) The increase in other revenue and other income of $7.3 million was mainly due to a gain on the sale of base pressure gas of $5.8 million, and higher late payment penalty revenues, which were higher than approved due to higher customer bills resulting primarily from colder than normal weather. This resulted 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 $0.6 million lower than the 2015 Board approved level primarily due to lower Customer Care and CIS support costs, and other miscellaneous underages, offset by higher other business costs. RCAM costs were also higher than approved, but offset by lower internal costs, due to the centralization of IT and HR services at Enbridge Inc. The net impact resulted 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 decrease in depreciation expense of $2.0 million is predominantly due to lower than forecast additions to in-service property, plant, and equipment, primarily due to delays in the GTA project which was originally forecast to be placed into service in October 2015, and higher than forecast retirements in the year, partially offset by the impact of higher than forecast actual 2015 opening depreciable plant balances. The decrease in depreciation resulted in a positive earnings impact.

e) Other expenses of $45.0 million were in line with the Board approved amount.

f) The increase in income taxes of $4.0 million is predominantly due to a higher utility income before tax amount resulting from the above noted items. The increase resulted in a negative earnings impact.

g) The interest cost of utility long and short term debt increased by $0.7 million primarily as a result of a higher outstanding principal balance required to fund a higher than forecast rate base value. The net impact has a negative earnings impact.

Witness: R. Small

RECONCILIATION OF AUDITED EGDI
CONSOLIDATED INCOME TO UTILITY INCOME
2015 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	3,042.8	2,442.8	(600.0)	a)
2.	Transportation of gas for customers	344.0	322.2	(21.8)	b)
3.	Other revenue and income	167.2	52.0	(115.2)	c)
4.		3,554.0	2,817.0	(737.0)	
	Expenses				
5.	Gas commodity and distribution costs	2,322.3	1,724.3	(598.0)	d)
6.	Operation and maintenance	508.6	430.7	(77.9)	e)
7.	Earnings sharing	7.1	-	(7.1)	f)
8.	Depreciation	289.9	259.7	(30.2)	g)
9.	Municipal and other taxes	-	41.6	41.6	h)
10.		3,127.9	2,456.3	(671.6)	
11.	Income before undernoted items	426.1	360.7	(65.4)	
12.	Interest and financing expenses	(180.8)	(3.4)	177.4	i)
13.	Income before income taxes	245.3	357.3	112.0	
14.	Income taxes	(10.7)	(19.4)	(8.7)	j)
15.	Net Income	234.6	337.9	103.3	

RECONCILIATION OF 2015
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	3,042.8	**Consolidated gas commodity and distribution revenue**
	(41.3)	Amounts related to St. Lawrence Gas
	(118.1)	Normalization adjustment
	(444.2)	US GAAP adjustment elimination - deferral clearance adjustment
	3.6	Gazifere T-service regrouped to gas commodity and distribution revenue
	2,442.8	**Utility gas commodity and distribution revenue**
b)	344.0	**Consolidated transportation of gas for customers**
	(10.9)	Amounts related to St. Lawrence Gas
	(7.1)	Normalization adjustment
	(3.6)	Gazifere T-service regrouped to gas commodity and distribution revenue
	(0.2)	Rounding
	322.2	**Utility transportation of gas for customers**
c)	167.2	**Consolidated other revenue and income**
	(20.7)	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
	0.4	Foreign exchange loss and other misc. expenses regrouped to O&M
	20.8	Allowable interest during construction regrouped to revenues from interest and financing expenses
	3.5	Interest on deferral accounts regrouped to revenues from interest and financing expenses
	(2.0)	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
	(13.5)	Open Bill expenses regrouped against program revenues from O&M
	(0.3)	Electric CDM expenses regrouped against program revenues from O&M
	(0.1)	Eliminate electric CDM net revenues
	(2.4)	Elimination of transactional services revenue above base amount included in rates
	(0.6)	To adjust OBA costs to reflect the EB-2013-0099 approved unit costs for determining net revenues
	(1.4)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(1.2)	Elimination of 3rd party asset use revenue considered non-utility
	(1.7)	Elimination of net ABC revenue considered non-utility
	(1.4)	Elimination of interest income from investments not included in rate base
	(20.8)	Elimination of allowable interest during construction
	(3.5)	Elimination of interest on deferral accounts
	(7.6)	Elimination of shareholder incentive income associated with the DSMIDA
	0.1	Rounding
	52.0	**Utility other revenue and income**

RECONCILIATION OF 2015
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	2,322.3	**Consolidated gas commodity and distribution costs**
	(38.3)	Elimination of amounts related to St. Lawrence Gas, unregulated storage
	(110.5)	Normalization adjustment
	(449.3)	US GAAP adjustment elimination - deferral clearance adjustment
	0.1	Rounding
	1,724.3	**Utility gas commodity and distribution costs**
e)	508.6	**Consolidated operation and maintenance**
	(44.1)	Municipal and other taxes included within O&M costs in the corp. financial statements
	(15.4)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(13.5)	Open Bill expenses regrouped against program revenues
	(2.0)	ABC administration and bad debt costs regrouped against program revenues and eliminated
	(0.3)	Electric CDM expenses regrouped against program revenues
	0.4	Foreign exchange loss and other misc. expenses regrouped from Other income
	0.7	Interest on security deposits added to utility O&M
	(1.2)	Elimination of donations
	(1.3)	Elimination of non-utility costs of supporting the ABC program
	5.1	US GAAP adjustment elimination - deferral clearance adjustment
	(6.3)	Elimination of Corporate Cost Allocations above RCAM amount
	430.7	**Utility operation and maintenance**
f)	7.1	**Consolidated earnings sharing**
	(7.1)	Elimination of 2015 earnings sharing amount within year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	289.9	**Consolidated depreciation**
	(7.0)	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
	0.1	Rounding
	259.7	**Utility depreciation**

RECONCILIATION OF 2015
AUDITED EGDI CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	-	**Consolidated municipal and other taxes**
	44.1	Municipal and other taxes included within O&M costs in the corp. financial statements
	(2.4)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	0.1	Rounding
	41.6	**Utility municipal and other taxes**
i)	180.8	**Consolidated interest and financing expenses**
	(2.9)	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
	20.8	Allowable interest during construction regrouped to revenues and eliminated
	3.5	Interest on deferral accounts regrouped to revenues and eliminated
	(0.1)	ABC interest charges regrouped against program revenues and eliminated
	(171.9)	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure
	3.4	**Utility interest and financing expenses**
j)	10.7	**Consolidated income taxes**
	(2.7)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(8.0)	Elimination of corporate income taxes
	19.4	Addition of income taxes calculated on a utility "stand-alone" basis
	19.4	**Utility income taxes**

Witness: R. Small

UTILITY RATE BASE (INCLUDING CUSTOMER CARE & CIS)
COMPARISON OF 2015 ACTUAL TO 2015 BOARD APPROVED

Line No.		Col. 1 2015 Actual	Col. 2 EB-2014-0276 2015 Board Approved	Col. 3 Variance
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	7,586.9	7,590.0	(3.1)
2.	Accumulated depreciation	(2,980.8)	(3,016.2)	35.4
3.	Net property, plant, and equipment	4,606.1	4,573.8	32.3
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.3	1.3	-
5.	Materials and supplies	38.9	33.7	5.2
6.	Mortgages receivable	-	0.1	(0.1)
7.	Customer security deposits	(59.8)	(65.1)	5.3
8.	Prepaid expenses	1.9	0.9	1.0
9.	Gas in storage	481.1	403.6	77.5
10.	Working cash allowance	10.3	8.2	2.1
11.	Total Working Capital	473.7	382.7	91.0
12.	Utility Rate Base	5,079.8	4,956.5	123.3

Witness: R. Small

UTILITY PROPERTY, PLANT, AND EQUIPMENT (INCLUDING CUSTOMER CARE & CIS)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2015 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	370.6	(131.2)	239.4
2.	Distribution plant	6,735.6	(2,575.0)	4,160.6
3.	General plant	491.9	(274.8)	217.1
4.	Other plant	0.2	(0.2)	-
5.	Total plant in service	7,598.3	(2,981.2)	4,617.1
6.	Plant held for future use	1.7	(1.2)	0.5
7.	Sub- total	7,600.0	(2,982.4)	4,617.6
8.	Affiliate Shared Assets Value	(13.1)	1.6	(11.5)
9.	Total property, plant, and equipment	7,586.9	(2,980.8)	4,606.1

Witness: R. Small

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2015	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)	45.9	0.1	-	46.0	(1.0)	45.0	44.9
3.	Structures and improvements (452.00)	17.5	0.1	(2.7)	14.9	(0.1)	14.9	16.6
4.	Wells (453.00)	48.0	2.2	(3.8)	46.5	-	46.5	48.0
5.	Well equipment (454.00)	10.3	0.2	(1.0)	9.5	-	9.5	10.1
6.	Field Lines (455.00)	79.5	7.0	(0.2)	86.3	-	86.3	83.7
7.	Compressor equipment (456.00)	109.9	9.0	(4.1)	114.9	(0.5)	114.4	112.1
8.	Measuring and regulating equipment (457.00)	11.6	0.1	(0.4)	11.2	-	11.2	11.5
9.	Base pressure gas (458.00)	40.9	-	(2.0)	38.9	-	38.9	39.4
10.	Total	367.7	18.7	(14.1)	372.4	(1.5)	370.9	370.6

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

Witness: R. Small

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
Line No.		Opening Balance Dec.2014	Additions	Net Salvage Adjustment	Retirements	Costs Net of Proceeds	Closing Balance Dec.2015	Regulatory Adjustments (Note 1)	Utility Balance Dec.2015	Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.4)	(0.1)	-	-	-	(2.4)	-	(2.4)	(2.4)
2.	Land and gas storage rights (451.00)	(22.8)	(0.5)	-	-	-	(23.3)	-	(23.3)	(23.1)
3.	Structures and improvements (452.00)	(6.0)	(0.1)	-	2.7	-	(3.5)	0.1	(3.4)	(5.3)
4.	Wells (453.00)	(22.1)	(0.7)	(0.0)	3.8	-	(19.1)	-	(19.1)	(21.4)
5.	Well equipment (454.00)	(6.1)	(0.6)	-	1.0	-	(5.7)	-	(5.7)	(6.1)
6.	Field Lines (455.00)	(24.9)	(1.3)	(0.0)	0.2	-	(26.0)	-	(26.0)	(25.4)
7.	Compressor equipment (456.00)	(40.9)	(3.0)	(0.1)	4.1	-	(39.9)	0.2	(39.7)	(41.0)
8.	Measuring and regulating equipment (457.00)	(6.5)	(0.3)	(0.0)	0.4	-	(6.4)	-	(6.4)	(6.5)
9.	Total	(131.7)	(6.5)	(0.1)	12.1	-	(126.3)	0.3	(126.1)	(131.2)

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

Witness: R. Small

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	19.4	0.1	-	19.5	-	19.5	19.4
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	11.1	0.1	-	11.2	-	11.2	11.2
4.	Structures and improvements (472.00)	129.9	10.2	(19.4)	120.7	(0.3)	120.4	124.2
5.	Services, house reg & meter install. (473/474)	2,475.9	136.9	(8.9)	2,603.9	-	2,603.9	2,528.6
6.	NGV station compressors (476)	3.1	0.3	-	3.3	-	3.3	3.3
7.	Meters (478)	414.7	25.0	(17.9)	421.8	-	421.8	416.9
8.	Sub-total	3,054.1	172.5	(46.2)	3,180.4	(0.3)	3,180.1	3,103.6
9.	Mains (475)	3,168.4	133.3	(3.7)	3,298.1	(2.2)	3,295.9	3,229.6
10.	Measuring and regulating equip. (477)	399.0	14.9	(1.9)	412.1	(0.5)	411.6	402.4
11.	Sub-total	3,567.4	148.3	(5.5)	3,710.1	(2.7)	3,707.4	3,632.0
12.	Total	6,621.5	320.7	(51.7)	6,890.5	(3.1)	6,887.5	6,735.6

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
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2015	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2015	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(2.0)	(0.1)	-	-	-	(2.1)	-	(2.1)	(2.1)
2.	Structures and improvements (472.00)	(23.5)	(6.5)	-	19.4	0.7	(9.8)	0.2	(9.6)	(19.8)
3.	Services, house reg & meter install. (473/474)	(1,022.3)	(57.3)	30.6	8.9	15.0	(1,025.1)	-	(1,025.1)	(1,023.2)
4.	NGV station compressors (476)	(2.0)	(0.2)	-	-	-	(2.2)	-	(2.2)	(2.1)
5.	Meters (478)	(147.5)	(38.5)	-	17.9	4.2	(163.8)	-	(163.8)	(160.0)
6.	Mains (475)	(1,176.0)	(70.6)	59.5	3.7	22.6	(1,160.9)	1.7	(1,159.2)	(1,164.3)
7.	Measuring and regulating equip. (477)	(200.8)	(8.4)	0.4	1.9	-	(207.0)	0.5	(206.4)	(203.6)
8.	Total	(2,574.1)	(181.6)	90.5	51.7	42.5	(2,570.9)	2.4	(2,568.5)	(2,575.0)

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

Witness: R. Small

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	6.4	(0.1)	(1.8)	4.5	(0.2) [1]	4.3	5.5
2.	Office furniture and equipment (483.00)	18.9	(0.3)	(1.1)	17.5	-	17.5	18.2
3.	Transportation equipment (484.00)	53.1	7.9	(8.0)	53.0	(0.1) [1]	53.0	51.2
4.	NGV conversion kits (484.01)	8.9	0.6	(5.5)	4.0	-	4.0	7.5
5.	Heavy work equipment (485.00)	21.7	1.1	(3.9)	18.9	-	18.9	20.7
6.	Tools and work equipment (486.00)	48.0	2.8	(1.7)	49.2	-	49.2	48.5
7.	Rental equipment (487.70)	1.1	0.3	-	1.3	-	1.3	1.1
8.	NGV rental compressors (487.80)	2.7	0.3	(0.8)	2.2	-	2.2	2.6
9.	NGV cylinders (484.02 and 487.90)	2.5	0.1	(1.9)	0.6	-	0.6	2.3
10.	Communication structures & equip. (488)	3.0	4.7	(3.0)	4.7	-	4.7	2.8
11.	Computer equipment (490.00)	39.6	(1.1)	(7.9)	30.7	-	30.7	37.1
12.	Software Aquired/Developed (491.00)	174.1	8.2	(7.0)	175.4	-	175.4	167.5
13.	CIS (491.00)	127.1	-	-	127.1	-	127.1	127.1
14	WAMS (489.00)	-	-	-	-	-	-	-
15	Total	507.1	24.5	(42.5)	489.1	(0.3)	488.9	491.9

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
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2015	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2015	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	(4.9)	(0.6)	1.8	-	(3.7)	0.2 [1]	(3.5)	(4.4)
2.	Office furniture and equipment (483.00)	(4.0)	(1.8)	1.1	-	(4.7)	-	(4.7)	(4.5)
3.	Transportation equipment (484.00)	(20.9)	(5.3)	8.0	(0.3)	(18.4)	0.1 [1]	(18.3)	(21.1)
4.	NGV conversion kits (484.01)	(6.5)	(0.3)	5.5	-	(1.4)	-	(1.4)	(5.2)
5.	Heavy work equipment (485.00)	(8.3)	(0.6)	3.9	(0.2)	(5.1)	-	(5.1)	(7.6)
6.	Tools and work equipment (486.00)	(15.5)	(2.0)	1.7	-	(15.8)	-	(15.8)	(16.4)
7.	Rental equipment (487.70)	(1.0)	-	-	-	(1.0)	-	(1.0)	(1.0)
8.	NGV rental compressors (487.80)	(2.1)	0.1	0.8	-	(1.3)	-	(1.3)	(2.0)
9.	NGV cylinders (484.02 and 487.90)	(2.3)	(0.3)	1.9	-	(0.7)	-	(0.7)	(2.3)
10.	Communication structures & equip. (488)	(2.5)	(3.1)	3.0	-	(2.5)	-	(2.5)	(2.3)
11.	Computer equipment (490.00)	(21.4)	(8.1)	7.9	-	(21.6)	-	(21.6)	(23.8)
12.	Software Aquired/Developed (491.00)	(96.9)	(37.7)	7.0	-	(127.6)	-	(127.6)	(111.2)
13.	CIS (491.00)	(66.7)	(12.7)	-	-	(79.5)	-	(79.4)	(73.1)
14.	Total	(252.9)	(72.3)	42.5	(0.4)	(283.2)	0.2	(283.0)	(274.8)

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

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	0.5	-	(0.5)	-	-	-	0.2
2.	Total	0.5	-	(0.5)	-	-	-	0.2

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2015	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2015	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	(0.5)	-	0.5	-	-	-	-	(0.2)
2.	Total	(0.5)	-	0.5	-	-	-	-	(0.2)

Witness: R. Small

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2014	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2015	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2015	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

Witness: R. Small

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.		Opening Balance Dec.2014	Additions	Retirements	Costs Net of Proceeds	Closing Balance Dec.2015	Regulatory Adjustment	Utility Balance Dec.2015	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)

Witness: R. Small

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2015 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	1.2	38.0	0.1	(60.8)	1.6	553.0	10.3	543.4
2.	January 31	1.3	37.5	-	(60.8)	1.5	479.8	10.3	469.6
3.	February	1.3	38.9	-	(60.7)	1.4	369.7	10.3	360.9
4.	March	1.3	37.7	-	(60.9)	2.2	306.0	10.3	296.6
5.	April	1.3	38.2	-	(60.6)	2.0	279.0	10.3	270.2
6.	May	1.3	39.4	-	(59.9)	1.9	337.5	10.3	330.5
7.	June	1.3	38.2	-	(58.6)	2.4	420.7	10.3	414.3
8.	July	1.3	39.7	-	(58.4)	2.3	500.1	10.3	495.3
9.	August	1.3	40.0	-	(58.4)	2.2	580.9	10.3	576.3
10.	September	1.3	39.1	-	(58.8)	2.0	650.9	10.3	644.8
11.	October	1.3	39.6	-	(59.3)	1.9	678.9	10.3	672.7
12.	November	1.4	40.3	-	(60.2)	2.3	636.3	10.3	630.4
13.	December	1.4	39.5	-	(60.3)	0.6	513.8	10.3	505.3
14.	Avg. of monthly avgs.	1.3	38.9	-	(59.8)	1.9	481.1	10.3	473.7

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2015 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	1,732.9	2.4	11.4
2.	Items not subject to working cash allowance (Note 1)	(8.6)		
3.	Gas costs charged to operations	1,724.3		
4.	Operation and Maintenance	430.7		
5.	Less: Storage costs	(8.0)		
6.	Operation and maintenance costs subject to working cash	422.7		
7.	Ancillary customer services	-		
8.		422.7	(11.1)	(12.9)
9.	Sub-total			(1.5)
10.	Storage costs	8.0	60.4	1.3
11.	Storage municipal and capital taxes	1.3	23.1	0.1
12.	Sub-total			1.4
13.	Harmonized Sales Tax			10.4
14.	Total working cash allowance			10.3

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

Witness: R. Small

COMPARISON OF UTILITY CAPITAL EXPENDITURES
2015 ACTUALS VS. 2015 BOARD APPROVED BUDGET

Table 1
Summary of Capital Expenditures 2015 Actual and 2015 Board Approved Budget
($millions)

Item		Col 1 Actual 2015	Col 2 Board Approved Budget 2015	Col 3 Actual Over/(Under) 2015
A	Customer Related Distribution Plant	145.5	130.4	15.1
B	System Improvements and Upgrades	208.5	247.8	(39.3)
C	General and Other Plant	55.8	52.7	3.1
D	Underground Storage Plant	26.9	15.7	11.2
E	**Sub total Core Capital Expenditures**	**436.7**	**446.6**	**(9.9)**
F	Work and Asset Management Solution (WAMS)	27.6	25.7	1.9
G	Leave to Construct - GTA Reinforcement	551.1	359.7	191.4
H	**Sub total Special Initiatives**	**578.7**	**385.4**	**193.3**
I	**Total Capital Expenditures**	**1,015.4**	**832.0**	**183.4**

1. The 2015 Actual expenditures for Work and Asset Management (WAMS) and Leave to Construct projects totaled $578.7 million, which was $193.3 million or 50.2% over the 2015 Budget of $385.4 million. Some of the overages are carryover costs from 2014 due to delays experienced with these multi-year initiatives. Both projects were budgeted to be in-service by end of 2015.

2. The 2015 Actual core capital expenditures were $436.7 million, which was $9.9 million or 2.2% less than the 2015 Budget of $446.6 million. Core capital includes overheads (i.e. departmental labour costs, capitalized administrative and general, and interest during construction). Excluding overheads, the 2015 Actual core capital spend was $329.4 million or 0.05% less than the 2015 Budget of $329.6 million.

3. Table 2 below shows the major drivers of the $183.4 million overspend vs. Board Approved budget and includes high-level commentary. Further details are provided below.

Table 2
2015 Actual vs. 2015 Board Approved Budget Major Variance
($millions)

		Actual Over/(Under)	% tage	Commentary
	Total 2015 Variance	**183.4**	**22%**	
A	LTC- GTA Reinforcement	191.4	53%	Delayed in-service date
B	Customer Growth	11.7	12%	Higher unit costs due to 3rd party cost pressures and customer mix
C	Storage	10.3	75%	Carry over costs related to compressor plant that was delayed in 2014.
D	Facilities and Genl Plant	9.2	42%	Evolving business needs (accelerated replacement of tools and fleet; carryover costs of building redesign)
E	Work and Asset Mgt (WAMS)	1.9	8%	Carry over costs from 2014; delayed in-service date due to design complexities
F	Reinforcements	(12.2)	-72%	York region reinforcement ($10M) deferred to 2018; Alliston deferred ($1M); and deferral of several smaller projects
G	Overheads -Departmental Labour Costs, AG and IDC	(9.9)	-8%	Workforce reductions; Lower IDC due to lower interest rates and lower CWIP base; partially offset by higher AG capitalized
H	Relocations	(8.4)	-63%	Dependency on external infrastructure timelines
I	Information Technology	(6.3)	-23%	Project delays are a direct result of WAMS delay
J	Business Development	(3.2)	-89%	NGV Rental program deferred to 2016
K	System Integrity and Reliability	(1.1)	-1%	Capital spend was the result of portfolio prioritization via risk based assessments
		183.4	**22%**	

A. Leave To Construct GTA Reinforcement – Overspent by $191.4 Million

4. The GTA Reinforcement project (Leave to Construct Application EB-2012-0099) is a multi-year infrastructure project with Segments A and B completed in March 2016. The project was delayed several months due to permitting issues and construction complexities. The project total is expected to be $922 million, which exceeds the project budget of $686 million. Please see Exhibit D1, Tab 1, Schedule 2 for more detail.

B. Customer Growth - Overspent by $11.7 Million

5. 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. 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.

C. Storage – Overspent by $10.3 Million

6. The overage is primarily driven by the compressor plant carryover costs from 2014 ($7.8 million) which was budgeted to commence construction in 2014. The remaining overage is due to compliance related requirements.

D. Facilities and General Plant – Overspent by $9.2 Million

7. 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 ($7.1 million). The remaining variance is due to costs related to office redesign and building improvements.

Witnesses: L. Au
T. Knight

E. Work and Asset Management Solution (WAMS) – Overspent by $1.9 Million

8. 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 occurred throughout 2015, into 2016, and "go live" is planned for Q3 2016. Delayed spend in 2014 due to a delay in starting the implementation phase resulted in additional spending in 2015. The overall project spend is expected to catch up to budgeted project spend by the project completion in 2016. The delayed in-service date is due to design complexities. Please see Exhibit D1, Tab 1, Schedule 3 for more detail.

F. Reinforcements – Underspent by $12.2 Million

9. Actual reinforcement requirements were considerably less than what had been budgeted, which had been based on customer growth forecasts received from developers. York Region Reinforcement ($10 million) was deferred until 2018 and Alliston Reinforcement ($1 million) was deferred indefinitely. The remaining variance is due to the deferral of several smaller reinforcements.

G. Departmental Labour Costs, A&G and IDC – Underspent by $9.9 Million

10. From an overall perspective, these three cost categories were 8% less than budget. The Company reduced the workforce and delayed filling vacancies as part of its productivity efforts as per its commitment under the Customized IR application. This productivity effort with Departmental Labour Costs accounts for $8.4 million of the underage. Interest during construction (IDC) is a function of the timing of actual construction costs. Due to the delay of several projects and a lower interest rate, actual IDC was $3.5 million less than the budget. The variance is partially offset by a $2.0 million overage in capitalized administrative and general (A&G) costs.

Witnesses: L. Au
T. Knight

H. Relocations - Underspent by $8.4 Million

11. Relocation activity is directly dependent on third party infrastructure timelines. The 2015 variance is primarily due to larger than anticipated recoveries associated with large scale infrastructure work such as, York Region Rapid Transit and Metrolinx. The Company works closely with external agencies to establish long range timelines.

I. Information Technology – Underspent by $6.3 Million

12. This variance is due to project delays that are a direct result of the WAMS delay.

J. Business Development – Underspent by $3.2 Million

13. The expansion of the NGV rental program has been deferred to 2016 due to a delay by the Company's client, the City of Toronto ($2.1 million). The remaining variance is due to the decision to redeploy existing Vehicle Rental Appliance (VRA) equipment rather than purchase new equipment.

K. System Integrity and Reliability (SIR) – Underspent by $1.1 Million

14. The SIR work for 2015 was the result of portfolio prioritization using risk based assessments. Please see Exhibit D, Tab 1, Schedule 4 for further details.

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Witnesses: L. Au
T. Knight

UTILITY OPERATING REVENUE (INCLUDING CUSTOMER CARE & CIS)
2015 ACTUAL

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	2,560.9	(118.1)	2,442.8
2.	Transportation of gas	329.3	(7.1)	322.2
3.	Transmission, compression & storage	1.9	-	1.9
4.	Other operating revenue	44.1	-	44.1
5.	Interest and property rental	-	-	-
6.	Other income	6.0	-	6.0
7.	Total operating revenue	2,942.2	(125.2)	2,817.0

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2015 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(118.1)	Gas sales Adjustment to gas sales revenue required to reflect normal weather.
2.	(7.1)	Transportation of gas Adjustment to gas transportation revenue required to reflect normal weather.

UTILITY REVENUE (INCLUDING CUSTOMER CARE & CIS)
2015 ACTUAL

		Col. 1	Col. 2	Col. 3
Line No.		EGDI Ont. Corporate Revenue	Adjustment	Utility Revenue
		($Millions)	($Millions)	($Millions)
1.	Residential	2,086.5	(444.2)	1,642.3
2.	Commercial	789.3	-	789.3
3.	Industrial	89.2	-	89.2
4.	Wholesale	40.1	-	40.1
5.	Gas sales	3,005.1	(444.2)	2,560.9
6.	Transportation of gas	329.3	-	329.3
7.	Transmission, compression & storage	1.9	-	1.9
8.	Service charges & DPAC	12.8	-	12.8
9.	Rent from NGV rentals	0.5	-	0.5
10.	Late payment penalties	13.2	-	13.2
11.	Transactional services	14.4	(2.4)	12.0
12.	Open bill revenue	7.4	(2.0)	5.4
13.	Dow Moore recovery	0.2	-	0.2
14.	Affiliate asset use revenue	-	-	-
15.	ABC T-service (net)	1.7	(1.7)	-
16.	Other operating revenue	50.2	(6.1)	44.1
17.	Income from investments	1.4	(1.4)	-
18.	Interest during construction	20.8	(20.8)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	3.5	(3.5)	-
21.	Property/asset use revenue 3rd party	1.2	(1.2)	-
22.	Interest and property rental	26.9	(26.9)	-
23.	Miscellaneous	15.7	(15.5)	0.2
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property/assets	5.8	-	5.8
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	84.2	(78.2)	6.0
28.	Total revenue	3,497.6	(555.4)	2,942.2

Witness: R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2015 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	(444.2)	Residential gas sales	
		US GAAP adjustment elimination, deferral & variance clearance recognition.	
11.	(2.4)	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.	(2.0)	Open bill revenue	
		To adjust OBA costs to reflect the EB-2013-0099 approved unit costs agreed to be used for determining net revenues.	(0.6)
		To eliminate the Open Bill shareholder incentive.	(1.4)
			(2.0)
15.	(1.7)	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
2015 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(1.4)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(20.8)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
20.	(3.5)	Interest on (net) deferral accounts	
		To eliminate interest income from assets not included in Utility rate base.	
21.	(1.2)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(15.5)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(7.8)
		To eliminate Electric CDM net revenues. Ratepayer amounts were transferred to the 2015 EPESDA and shareholder amounts are eliminated from utility results.	(0.1)
		To eliminate the shareholders' incentive income recorded as a result of calculating the 2014 DSMIDA amount.	(7.6)
			(15.5)
24.	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	

Witness: R. Small

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2015 ACTUAL AND 2015 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2015 Actual	Col. 2 2015 Board Approved Budget	Col. 3 2015 Actual Over (Under) 2015 Budget (1-2)
General Service				
1.1.1	Rate 1 - Sales	4 558.1	4 199.8	358.3
1.1.2	Rate 1 - T-Service	438.9	476.0	(37.1)
1.1	Total Rate 1	4 997.0	4 675.8	321.2
1.2.1	Rate 6 - Sales	2 897.8	2 894.3	3.5
1.2.2	Rate 6 - T-Service	2 108.8	1 800.7	308.1
1.2	Total Rate 6	5 006.6	4 695.0	311.6
1.3.1	Rate 9 - Sales	0.3	0.5	(0.2)
1.3.2	Rate 9 - T-Service	0.0	0.1	(0.1)
1.3	Total Rate 9	0.3	0.6	(0.3)
1.	Total General Service Sales & T-Service	10 003.9	9 371.4	632.5
Contract Sales				
2.1	Rate 100	3.6	0.0	3.6
2.2	Rate 110	42.8	72.2	(29.4)
2.3	Rate 115	0.0	1.2	(1.2)
2.4	Rate 135	2.3	3.7	(1.4)
2.5	Rate 145	13.1	20.0	(6.9)
2.6	Rate 170	35.0	39.7	(4.7)
2.7	Rate 200	176.4	169.1	7.3
2.	Total Contract Sales	273.2	305.9	(32.7)
Contract T-Service				
3.1	Rate 100	0.1	0.0	0.1
3.2	Rate 110	625.1	423.1	202.0
3.3	Rate 115	512.2	530.8	(18.6)
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	66.3	54.3	12.0
3.6	Rate 145	64.4	118.9	(54.5)
3.7	Rate 170	359.8	453.2	(93.4)
3.8	Rate 300	26.8	30.0	(3.2)
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	1 654.7	1 610.3	44.4
4.	Total Contract Sales & T-Service	1 927.9	1 916.2	11.7
5.	Total	11 931.8	11 287.6	644.2

* There is no distribution volume for Rate 125 customers.

Witnesses: R. Cheung
C. Ho

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2015 ACTUAL AND 2015 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2015 Actual	Col. 2 2015 Board Approved Budget	Col. 3 2015 Actual Over (Under) 2015 Budget (1-2)	Col. 4 2015* Adjustments	Col. 5 2015 Actual Over (Under) 2015 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	4 558.1	4 199.8	358.3	(280.9)	77.4
1.1.2	Rate 1 - T-Service	438.9	476.0	(37.1)	(30.4)	(67.5)
1.1	Total Rate 1	4 997.0	4 675.8	321.2	(311.3)	9.9
1.2.1	Rate 6 - Sales	2 897.8	2 894.3	3.5	(194.9)	(191.4)
1.2.2	Rate 6 - T-Service	2 108.8	1 800.7	308.1	(105.4)	202.7
1.2	Total Rate 6	5 006.6	4 695.0	311.6	(300.3)	11.3
1.3.1	Rate 9 - Sales	0.3	0.5	(0.2)	0.0	(0.2)
1.3.2	Rate 9 - T-Service	0.0	0.1	(0.1)	0.0	(0.1)
1.3	Total Rate 9	0.3	0.6	(0.3)	0.0	(0.3)
1.	Total General Service Sales & T-Service	10 003.9	9 371.4	632.5	(611.6)	20.9
Contract Sales						
2.1	Rate 100	3.6	0.0	3.6	0.0 **	3.6
2.2	Rate 110	42.8	72.2	(29.4)	(0.1)	(29.5)
2.3	Rate 115	0.0	1.2	(1.2)	0.0	(1.2)
2.4	Rate 135	2.3	3.7	(1.4)	0.0	(1.4)
2.5	Rate 145	13.1	20.0	(6.9)	2.5	(4.4)
2.6	Rate 170	35.0	39.7	(4.7)	2.9	(1.8)
2.7	Rate 200	176.4	169.1	7.3	(8.3)	(1.0)
2.	Total Contract Sales	273.2	305.9	(32.7)	(3.0)	(35.7)
Contract T-Service						
3.1	Rate 100	0.1	0.0	0.1	0.0 **	0.1
3.2	Rate 110	625.1	423.1	202.0	(2.0)	200.0
3.3	Rate 115	512.2	530.8	(18.6)	0.0	(18.6)
3.4	Rate 125	0.0	0.0	0.0	0.0	0.0
3.5	Rate 135	66.3	54.3	12.0	0.0	12.0
3.6	Rate 145	64.4	118.9	(54.5)	(1.0)	(55.5)
3.7	Rate 170	359.8	453.2	(93.4)	(8.4)	(101.8)
3.8	Rate 300	26.8	30.0	(3.2)	0.0	(3.2)
3.9	Rate 315	0.0	0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 654.7	1 610.3	44.4	(11.4)	33.0
4.	Total Contract Sales & T-Service	1 927.9	1 916.2	11.7	(14.4)	(2.7)
5.	Total	11 931.8	11 287.6	644.2	(626.0)	18.2

*Note: Weather normalization adjustments have been made to the 2015 Actual utilizing the 2015 Board Approved Budget Degree Days.

** Less than 50,000 m^3

Witnesses: R. Cheung
C. Ho

The principal reasons for the variances contributing to the weather normalized increase of 18.2 10^6m^3 in the 2015 Actual over the 2015 Board Approved Budget are as follows:

1. The volumetric increase of 9.9 10^6m^3 in Rate 1 was due to a higher average use per customer totaling 16.8 10^6m^3 and partially offset by unfavourable customer variance of 6.9 $10^6m^{3;}$

2. The volumetric increase of 11.3 10^6m^3 in Rate 6 was due to a higher average use per customer totaling 42.7 10^6m^3; partially offset by unfavourable customer variance of 30.8 10^6m^3 and net customer migration to Contract Sales and T-Service of 0.6 10^6m^3;

3. The volumetric decrease of 0.3 10^6m^3 in Rate 9 was due to a lower average use per station and the loss of one station;

4. The volumetric decrease for Contract Sales and T-Service of 2.7 10^6m^3 was due to decreases in the commercial sector of 15.2 10^6m^3 and Rate 200 of 1.0 10^6m^3; partially offset by the increases in industrial sector and the apartment sector of 13.5 10^6m^3 .

Witnesses: R. Cheung
C. Ho

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2015 HISTORICAL YEAR AND 2015 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2015 Actual	Col. 2 2015 Board Approved Budget	Col. 3 2015 Actual Over (Under) 2015 Budget (1-2)	Col. 4 2015* Adjustments	Col. 5 2015 Actual Over (Under) 2015 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 663.3	1 548.7	114.6	(79.3)	35.3
1.1.2	Rate 1 - T-Service	97.2	90.6	6.6	(2.9)	3.7
1.1	Total Rate 1	1 760.5	1 639.3	121.2	(82.2)	39.0
1.2.1	Rate 6 - Sales	855.8	848.2	7.6	(47.1)	(39.5)
1.2.2	Rate 6 - T-Service	186.8	134.0	52.8	(6.0)	46.8
1.2	Total Rate 6	1 042.6	982.2	60.4	(53.1)	7.3
1.3.1	Rate 9 - Sales	0.1	0.2	(0.1)	0.0	(0.1)
1.3.2	Rate 9 - T-Service	0.0 **	0.0 **	0.0 **	0.0	0.0 **
1.3	Total Rate 9	0.1	0.2	(0.1)	0.0	(0.1)
1.	Total General Service Sales & T-Service	2 803.2	2 621.7	181.5	(135.3)	46.2
Contract Sales						
2.1	Rate 100	0.8	0.0	0.8	0.0 **	0.8
2.2	Rate 110	9.5	15.9	(6.4)	0.0 **	(6.4)
2.3	Rate 115	0.0	0.3	(0.3)	0.0	(0.3)
2.4	Rate 135	0.4	0.8	(0.4)	0.0	(0.4)
2.5	Rate 145	3.0	4.3	(1.3)	0.0	(1.3)
2.6	Rate 170	7.3	7.7	(0.4)	0.0	(0.4)
2.7	Rate 200	33.9	29.7	4.2	(1.9)	2.3
2.	Total Contract Sales	54.9	58.7	(3.8)	(1.9)	(5.7)
Contract T-Service						
3.1	Rate 100	0.1	0.0	0.1	0.0 **	0.1
3.2	Rate 110	28.6	14.9	13.7	0.0 **	13.7
3.3	Rate 115	9.6	8.5	1.1	0.0 **	1.1
3.4	Rate 125	9.9	9.8	0.1	0.0 ***	0.1
3.5	Rate 135	3.6	1.5	2.1	0.0	2.1
3.6	Rate 145	2.3	3.0	(0.7)	0.0 **	(0.7)
3.7	Rate 170	9.0	2.1	6.9	0.1	7.0
3.8	Rate 300	0.1	0.2	(0.1) **	0.0	(0.1)
3.9	Rate 315	0.5	0.0	0.5	0.0	0.5
3.	Total Contract T-Service	63.7	40.0	23.7	0.1	23.8
4.	Total Contract Sales & T-Service	118.6	98.7	19.9	(1.8)	18.1
5.	Total	2 921.8	2 720.4	201.4	(137.1)	64.3

* Note: Weather normalization adjustments have been made to the 2015 Actuals utilizing the 2015 Board Approved Budget degree days. Please refer to Exhibit B, Tab 3, Schedule 2, page 2, for the corresponding volumetric adjustments.

** Less than $50,000

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

Witnesses: R. Cheung
C. Ho

1. Gas sales and transportation of gas revenues for the 2015 Test Year Budget were developed on the basis of EB-2014-0276 rates.

2. The principal reasons for the variance of $201.4 million in the 2015 Actual compared to the 2015 Budget are as follows:

3. Gas Sales - Increase of $118.3 Million

   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. Transportation of Gas - Increase of $83.1 Million

   The increase in T-service revenue was mainly due to higher T-service volume than budgeted.

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

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2015 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	1 764 950	4 558.1	1 663.3	
1.1.2	Rate 1 - T-Service	165 707	438.9	97.2	
1.1	Total Rate 1	1 930 657	4 997.0	1 760.5	
1.2.1	Rate 6 - Sales	138 808	2 897.8	855.8	
1.2.2	Rate 6 - T-Service	24 826	2 108.8	186.8	
1.2	Total Rate 6	163 634	5 006.6	1 042.6	
1.3.1	Rate 9 - Sales	5	0.3	0.1	
1.3.2	Rate 9 - T-Service	1	0.0	0.0	**
1.3	Total Rate 9	6	0.3	0.1	
1.	Total General Service Sales & T-Service	2 094 297	10 003.9	2 803.2	
Contract Sales					
2.1	Rate 100	1	3.6	0.8	
2.2	Rate 110	32	42.8	9.5	
2.3	Rate 115	0	0.0	0.0	
2.4	Rate 135	1	2.3	0.4	
2.5	Rate 145	7	13.1	3.0	
2.6	Rate 170	4	35.0	7.3	
2.7	Rate 200	1	176.4	33.9	
2.	Total Contract Sales	46	273.2	54.9	
Contract T-Service					
3.1	Rate 100	1	0.1	0.1	
3.2	Rate 110	195	625.1	28.6	
3.3	Rate 115	25	512.2	9.6	
3.4	Rate 125	5	0.0 *	9.9	
3.5	Rate 135	41	66.3	3.6	
3.6	Rate 145	45	64.4	2.3	
3.7	Rate 170	22	359.8	9.0	
3.8	Rate 300	2	26.8	0.1	
3.9	Rate 315	2	0.0	0.5	
3.	Total Contract T-Service	338	1 654.7	63.7	
4.	Total Contract Sales & T-Service	384	1 927.9	118.6	
5.	Total	2 094 681	11 931.8	2 921.8	

* There is no distribution volume for Rate 125 customers.

** Less than $50,000.

Witnesses: R. Cheung
C. Ho

DETAILS OF OTHER REVENUE AND OTHER INCOME
2015 ACTUAL AND 2015 BOARD APPROVED

		Col. 1	Col. 2	Col. 3
Item No.		2015 Actual ($Millions)	2015 Board Approved Budget ($Millions)	2015 Actual Over/(Under) 2015 Board Approved ($Millions)
1.1	Service Charges & DPAC	12.8	12.2	0.6
1.2	Rental Revenue - NGV Program	0.5	0.9	(0.4)
1.3	Late Payment Penalties	13.2	10.1	3.1 *
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	6.0	1.9	4.1 **
1.7	Open Bill Revenue	5.4	5.4	-
1.8	Total Other Revenue	50.1	42.8	7.3

Notes:
* Late Payment Penalties are $3.1m over budget due to higher customer bills caused by the colder winter and higher price of gas.

**Miscellaneous and Other Income is ($4.1m) over budget mainly due gain on sale of base pressure gas revenue of $5.8m partially offset by $1.8m due to the EB-2012-0459 decision on Other Revenue bringing the 2015 Board Approved Budget to $42.8m. The adjustment of $1.8m over the original filed amount of $40.6m was not allocated to any specific item.

Witnesses: S. Purba
R. Small

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2015 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	1,834.8	(110.5)	1,724.3
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	430.7	-	430.7
3.	Depreciation and amortization expense	259.7	-	259.7
4.	Fixed financing costs	3.4	-	3.4
5.	Municipal and other taxes	41.6	-	41.6
6.	Operating costs	2,570.2	(110.5)	2,459.7
7.	Income tax expense			19.4
8.	Cost of service			2,479.1

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2015 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	(110.5)	Gas costs Adjustment required to gas costs to reflect normal weather.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2015 ACTUAL

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	357.3	357.3	
	Add			
2.	Depreciation and amortization	259.7	259.7	
3.	Accrual based pension and OPEB costs	37.3	37.3	
4.	Other non-deductible items	0.6	0.6	
5.	Total Add Back	297.6	297.6	
6.	Sub-total	654.9	654.9	
	Deduct			
7.	Capital cost allowance	246.3	246.3	
8.	Items capitalized for regulatory purposes	77.6	77.6	
9.	Deduction for "grossed up" Part VI.1 tax	3.1	3.1	
10.	Amortization of share/debenture issue expense	1.2	1.2	
11.	Amortization of cumulative eligible capital	0.3	0.3	
12.	Amortization of C.D.E. and C.O.G.P.E	0.4	0.4	
13.	Site Rest Costs adjustment	90.4	90.4	
14.	Cash based pension and OPEB costs	6.6	6.6	
15.	50% of capital gain on sale of assets	2.9	2.9	
16.	Total Deduction	428.8	428.8	
17.	Taxable income	226.1	226.1	
18.	Income tax rates	15.00%	11.50%	
19.	Provision	33.9	26.0	59.9
20.	Part VI.1 tax			0.9
21.	Total taxes excluding interest shield			60.8
	Tax shield on interest expense			
22.	Rate base	5,079.8		
23.	Return component of debt	3.07%		
24.	Interest expense	156.1		
25.	Combined tax rate	26.500%		
26.	Income tax credit			(41.4)
27.	Total utility income taxes			19.4

Witness: R. Small

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2015 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	2,284.1	(449.3)	1,834.8
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	440.8	(10.1)	430.7
3.	Depreciation	260.5	(0.8)	259.7
4.	Amortization	22.5	(22.5)	-
5.	Depreciation and amortization	283.0	(23.3)	259.7
6.	Fixed financing costs	3.4	-	3.4
7.	Municipal and other taxes	41.8	(0.2)	41.6
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	41.8	(0.2)	41.6
10.	Interest on long-term debt	158.6	(158.6)	-
11.	Amortization of preference share issue costs and debt discount and expense	0.9	(0.9)	-
				-
12.	Interest and financing amortization	159.5	(159.5)	-
13.	Interest on short-term debt	14.2	(14.2)	-
14.	Interest due affiliates	27.3	(27.3)	-
				-
15.	Other interest expense	41.5	(41.5)	-
16.	Total operating costs	3,254.1	(683.9)	2,570.2
17.	Current taxes	(4.7)	4.7	-
18.	Deferred taxes	14.8	(14.8)	-
19.	Income tax expense	10.1	(10.1)	-
20.	Cost of service	3,264.2	(694.0)	2,570.2

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2015 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1	(449.3)	Gas costs	
		US GAAP adjustment elimination, deferral & variance clearance recognition.	
2.	(10.1)	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.	0.7
		To eliminate donations (EBRO 490).	(1.2)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(1.3)
		US GAAP adjustment elimination, deferral & variance clearance recognition.	5.1
		To eliminate Corporate Cost allocations above RCAM amount.	(6.3)
		To eliminate earnings sharing recorded in the financial statements.	(7.1)
			(10.1)
3.	(0.8)	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)
			(0.8)
4.	(22.5)	Amortization expense	
		To eliminate the amortization of PPD.	
9.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

Witness: R. Small

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2015 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
10.	(158.6)	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.	(14.2)	Interest on short-term debt	
		Expense of capital.	
14.	(27.3)	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.	(0.5)
			(27.3)
17.	4.7	Income taxes - current	
		Income tax expense related to corporate earnings.	
18.	(14.8)	Income taxes - deferred	
		Income tax expense related to corporate earnings.	

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2015 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 F2015	UCC Carry Forward
1	1,716,518,613	-	-	-	4.00%	(68,660,745)	1,647,857,869
51	1,846,228,390	228,391,611	150,000	114,270,806	6.00%	(117,629,952)	1,957,140,050
2	104,778,003	-	(560,944)	(280,472)	6.00%	(6,269,852)	97,947,208
6	11,055	-	-	-	10.00%	(1,106)	9,950
8	10,916,840	4,873,806	-	2,436,903	20.00%	(2,670,749)	13,119,898
10	24,797,559	12,241,419	(401,494)	5,919,963	30.00%	(9,215,257)	27,422,228
12	17,686,728	15,251,399	-	7,625,699	100.00%	(25,312,427)	7,625,699
17	27,411	-	-	-	8.00%	(2,193)	25,218
38	3,972,888	-	(64,050)	(32,025)	30.00%	(1,182,259)	2,726,579
41	26,034,380	18,993,942	(1,099,952)	8,946,995	25.00%	(8,745,344)	35,183,027
13	1,873,492	55,000	-	27,500	-	(249,000)	1,679,492
3	213,639	-	-	-	5.00%	(10,682)	202,957
45	148,148	-	-	-	45.00%	(66,667)	81,482
50	7,243,293	5,876,016	-	2,938,008	55.00%	(5,599,716)	7,519,593
Total	3,760,450,439	285,683,193	(1,976,439)	141,853,377		(245,615,946)	3,798,541,247

Non-utility and shared asset eliminations	(656,011)
Utility Federal CCA	(246,271,957)

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 F2015	UCC Carry Forward
1	1,716,518,613	-	-	-	4.00%	(68,660,745)	1,647,857,869
51	1,846,228,390	228,391,611	150,000	114,270,806	6.00%	(117,629,952)	1,957,140,050
2	104,778,003	-	(560,944)	(280,472)	6.00%	(6,269,852)	97,947,208
6	11,055	-	-	-	10.00%	(1,106)	9,950
8	10,916,840	4,873,806	-	2,436,903	20.00%	(2,670,749)	13,119,898
10	24,797,559	12,241,419	(401,494)	5,919,963	30.00%	(9,215,257)	27,422,228
12	17,686,728	15,251,399	-	7,625,699	100.00%	(25,312,427)	7,625,699
17	27,411	-	-	-	8.00%	(2,193)	25,218
38	3,972,888	-	(64,050)	(32,025)	30.00%	(1,182,259)	2,726,579
41	26,034,380	18,993,942	(1,099,952)	8,946,995	25.00%	(8,745,344)	35,183,027
13	1,873,492	55,000	-	27,500	-	(249,000)	1,679,492
3	213,639	-	-	-	5.00%	(10,682)	202,957
45	148,148	-	-	-	45.00%	(66,667)	81,482
50	7,243,293	5,876,016	-	2,938,008	55.00%	(5,599,716)	7,519,593
Total	3,760,450,439	285,683,193	(1,976,439)	141,853,377		(245,615,946)	3,798,541,247

Non-utility and shared asset eliminations	(656,011)
Utility Provincial CCA and UCC	(246,271,957)

Witness: R. Small

2015 UTILITY O&M

Line No.	Particulars ($000's)	Actuals 2015	IR 2015	Difference
1	Operations (including Pipeline Integrity and Engineering)	$ 105,667	$ 107,174	$ 1,507
2	Human Resources and Facilities*	32,790	22,462	(10,328)
3	Employee Benefits	28,114	26,350	(1,764)
4	Short Term Incentive Program	28,165	21,628	(6,537)
5	Information Technology	18,037	26,976	8,939
6	Regulatory, Public and Government Affairs	16,434	20,914	4,480
7	Finance	12,450	11,979	(471)
8	Provision for Uncollectibles (Bad Debts)	10,033	9,500	(533)
9	Customer Care (Exclude CC/CIS and Bad Debts)	3,176	2,399	(777)
10	Business Development & Customer Strategy (excluding DSM)	3,715	6,363	2,648
11	Legal and Corporate Security	4,335	5,370	1,035
12	Energy Supply and Policy	4,695	4,348	(347)
13	Non Departmental Expenses	3,121	3,669	548
14	Capitalization (A&G)	(41,408)	(37,740)	3,668
15	Interest on Security Deposit	698	2,019	1,322
16	Regulatory Eliminations	(3,283)	(3,192)	91
17	Other O&M Subtotal	$ 226,739	$ 230,220	$ 3,481
18	Customer Care/CIS Service Charges	84,848	94,800	9,952
19	Pensions and OPEB	37,361	37,361	-
20	RCAM	47,000	33,962	(13,038)
21	Demand Side Management Programs (DSM)	34,955	34,955	-
22	Conservation Services		-	-
23	Total Net Utility O&M Expense before Eliminations	$ 430,903	$ 431,298	$ 395

2015 Actuals revised to reflect IR org structure

**Includes $15.3M actual 2015 severances vs. $2.2M 2015 IR Budget severances*

Witnesses: A. Patel
L. Stickles

EXPLANATION OF MAJOR CHANGES
ACTUAL 2015 O&M EXPENSES COMPARED TO OEB APPROVED 2015 O&M EXPENSES

The 2015 Actual Utility O&M was $430.9 million, which was $0.4 million lower than the 2015 OEB approved Utility O&M. The decrease was driven by the following areas:

Line No:

1. Operations decreased by $1.5M mostly due to lower in-line inspection activity, higher third party damage recoveries and a different mix of work within O&M versus capital activities. These were partially offset by higher extra high pressure and high pressure survey costs.

2. Human Resources and Facilities increased $10.3M primarily due to staff reductions which resulted in higher severances. This was partially offset by lower salaries and wages costs and lower payroll and benefits services costs, as these functions were centralized at Enbridge Inc., and by lower costs for rents and leases.

3. Employee Benefits increased $1.8M from higher employee deductions (ex. CPP, EI, EHT, etc), higher employee use of benefit and dental plans and long term disability, and higher life insurance costs.

4. Short Term Incentive Program increased by $6.5M. The Company achieved higher than a one multiplier on all three factors that STIP is measured on.

5. Information Technology decreased by $8.9M primarily due to IT shared services being centralized at Enbridge Inc., partially offset by a shift in work load from more capital related projects to more support related projects.

6. Regulatory, Public and Government Affairs decreased $4.5M from lower customer and stakeholder communication programs, lower sponsorships and donations, lower rate hearing costs, and lower regulatory consulting costs.

Witnesses: A. Patel
L. Stickles

10. Business Development and Customer Strategy decreased $2.6M 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.

11. Legal and Corporate Security decreased by $1M from lower legal fees, lower salaries and wages from staff lags, and lower records management and corporate security activity.

14. Capitalization (Admin and General) increased $3.7M. This is from higher HR related costs (i.e. STIP and benefits), and higher support costs related to the GTA project.

15. Interest on Security Deposits decreased $1.3M. This is from lower security deposits from higher refunding of the excess deposits over $250 as per a new policy affected in 2014, reduced aging on AR balances resulting in less security deposits required, and a higher number of customers on Pre-Authorized Payments (PAP) which does not require a security deposit.

18. Customer Care/CIS Service Charges decreased $10M. 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.

20. RCAM increased $13M from the centralization of IT shared services and HR payroll and benefit services to Enbridge Inc. The offsetting decrease is in the IT and HR departments as noted in lines 2 and 5.

Witnesses: A. Patel
L. Stickles

REVENUE DEFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN (INCLUDING CUSTOMER CARE & CIS)
2015 ACTUAL

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (col 1x col 3)
Line No.		Principal	Component	Cost Rate	Return Component	Interest & pref share Expense
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,985.7	58.78	5.15	3.030	153.9
2.	Short-Term Debt	165.4	3.25	1.32	0.043	2.2
3.		3,151.1	62.03		3.073	
4.	Preference Shares	100.0	1.97	2.24	0.044	2.2
5.	Common Equity	1,828.7	36.00	9.30	3.348	158.3
6.		5,079.8	100.00		6.465	
7.	Rate Base	($Millions)			5,079.8	
8.	Utility Income	($Millions)			337.9	
9.	Indicated Rate of Return				6.652	
10.	Sufficiency in Rate of Return				0.187	
11.	Net Sufficiency	($Millions)			9.5	
12.	Gross Sufficiency	($Millions)			12.9	
13.	Revenue at Existing Rates	($Millions)			2,766.9	
14.	Allowed Revenue	($Millions)			2,754.0	
15.	Gross Revenue Sufficiency	($Millions)			12.9	
	Common Equity					
16.	Allowed Rate of Return				9.300	
17.	Earnings on Common Equity				9.819	
18.	Sufficiency in Common Equity Return				0.519	

Witness: R. Small

UTILITY INCOME (INCLUDING CIS & CUSTOMER CARE)
2015 ACTUAL

Line No.		Col. 1 Utility Income Incl. CIS & Customer Care ($Millions)
1.	Gas sales	2,442.8
2.	Transportation of gas	322.2
3.	Transmission, compression and storage revenue	1.9
4.	Other operating revenue	44.1
5.	Interest and property rental	-
6.	Other income	6.0
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,817.0
8.	Gas costs	1,724.3
9.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	430.7
10.	Depreciation and amortization expense	259.7
11.	Fixed financing costs	3.4
12.	Municipal and other taxes	41.6
13.	Interest and financing amortization expense	-
14.	Other interest expense	-
15.	Cost of service (Ex. B-4-1-pg.1)	2,459.7
16.	Utility income before income taxes	357.3
17.	Income tax expense (Ex. B-4-1-pg.3)	19.4
18.	Utility income	337.9

Witness: R. Small

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2015 ACTUAL

		Col. 1	Col. 2	Col. 3
Line No.		Average of Monthly Averages		Carrying Cost
		($Millions)		($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	2,976.3		153.4
2.	Unamortized Finance Costs	9.4		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,985.7		153.4
5.	Calculated Cost Rate		5.15%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.32%	
	Preference Shares			
7.	Preference Share Summary	100.0		2.2
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		2.2
11.	Calculated Cost Rate		2.24%	
	Common Equity			
12.	Board Formula ROE		9.30%	

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2015 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.	5.21%	February 25, 2036	300.0	5.183%	15.5
9.	4.77%	December 17, 2021	175.0	5.310%	9.3
10.	5.16%	December 4, 2017	200.0	5.220%	10.4
11.	4.04%	November 23, 2020	200.0	5.209%	10.4
12.	4.95%	November 22, 2050	200.0	4.990%	10.0
13.	4.95%	November 22, 2050	100.0	4.731%	4.7
14.	4.04%	November 23, 2020	200.0	2.801%	5.6
15.	4.50%	November 23, 2043	200.0	4.198%	8.4
16.	1.85%	April 24, 2017	-	1.967%	- [1]
17.	3.15%	August 22, 2024	215.0	3.241%	7.0
18.	4.00%	August 22, 2044	215.0	3.889%	8.4
19.	4.00%	August 22, 2044	49.6	4.436%	2.2
20.	3.31%	September 11, 2025	116.7	3.619%	4.2
21.			2,891.3		145.0
Long-Term Debentures					
22.	9.85%	December 2, 2024	85.0	9.910%	8.4
23.			85.0		8.4
24.	Total Term Debt		2,976.3		153.4

Notes:

1. Enbridge's April 2014 issuance of a $300 million three-year note has been removed from the calculation of long and medium-term debt costs, and has been re-categorized to short-term debt in a manner consistent with the treatment approved within the Settlement Agreement in Enbridge's 2015 Rate Adjustment proceeding, EB-2014-0276.

UNAMORTIZED DEBT DISCOUNT AND EXPENSE
AVERAGE OF MONTHLY AVERAGES
2015 ACTUAL

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	(17.9)
2.	January 31	(17.9)
3.	February	(17.9)
4.	March	(17.9)
5.	April	(18.0)
6.	May	(18.0)
7.	June	(18.0)
8.	July	(18.0)
9.	August	(18.0)
10.	September	11.6
11.	October	11.5
12.	November	11.5
13.	December	11.4
14.	Average of Monthly Averages	(9.4)

Witness: R. Small

DEFERRAL & VARIANCE ACCOUNTS
REQUESTED FOR CLEARANCE OCTOBER 1, 2016

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, 2016. The balances requested for clearance total approximately $67.3 million, which is the combination of principal and interest amounts shown in Columns 3 and 4.

2. Included within the accounts requested for clearance are the 2014 DSM related deferral account balances (2014 DSMVA, LRAM, and DSMIDA) which are currently under review as part of the EB-2015-0267 proceeding. While the Company anticipates clearing these accounts in conjunction with the account balances approved as part of this proceeding, the actual 2014 DSM related account balances cleared will be those approved by the Board as part of the EB-2015-0267 proceeding. The 2015 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.

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, 2016 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 2015 Manufactured Gas Plant Deferral Account ("MGPDA"), the 2015 Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA"), or the 2015 Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA").

6. The December 31, 2015 MGPDA principal and interest balances were transferred to corresponding 2016 accounts in accordance with the 2015 account descriptions approved within EB-2015-0114. Clearance of amounts recorded in the MGPDA will be requested in a future proceeding.

7. The December 31, 2015 CDNSADA principal balance was transferred to the corresponding 2016 account in accordance with the account scope and methodology that was approved within EB-2012-0459, and as further documented within the 2016 account description approved within EB-2015-0114. Any balance recorded in the CDNSADA at the end of 2018 will be requested for clearance in a post 2018 true-up.

8. The December 31, 2015 GGEIDA principal and interest balances were transferred to corresponding 2016 accounts, as the Company's 2015 costs relate only to very early stages of assessing operational and cost implications of becoming compliant with the Ontario government's proposed cap and trade regulations. As indicated in the EB-2015-0114 proceeding, the Company expects that it will incur further costs in 2016 as it prepares for the implementation of the cap and trade system. Enbridge will request clearance of amounts recorded in the GGEIDA in a future proceeding.

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at March 31, 2016 Principal ($000's)	Col. 2 Actual at March 31, 2016 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2016 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2016 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2014 DSMVA	352.5	5.2	352.5	7.0 [1]
2.	Demand Side Management V/A	2015 DSMVA	1,391.4	3.8	-	- [2]
3.	Lost Revenue Adjustment Mechanism	2014 LRAM	(65.3)	(0.2)	(65.3)	(0.8) [1]
4.	Demand Side Management Incentive D/A	2014 DSMIDA	7,647.2	28.0	7,647.2	70.0 [1]
5.	Deferred Rebate Account	2015 DRA	419.0	0.4	419.0	2.8 [3]
6.	Manufactured Gas Plant D/A	2016 MGPDA	537.7	35.0	-	- [4]
7.	Electric Program Earnings Sharing D/A	2015 EPESDA	(59.3)	(0.2)	(59.3)	(0.8) [5]
8.	Gas Distribution Access Rule Impact D/A	2015 GDARIDA	-	-	295.2	- [6]
9.	Average Use True-Up V/A	2015 AUTUVA	(2,278.3)	(6.3)	(2,278.3)	(18.9) [7]
10.	Earnings Sharing Mechanism Deferral Account	2015 ESMDA	(6,450.0)	(17.7)	(6,450.0)	(53.1) [8]
11.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	11.7	-	20.1 [9]
12.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	21.5	-	43.1 [9]
13.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	34.1	-	68.1 [9]
14.	Transition Impact of Accounting Changes D/A	2016 TIACDA	75,408.6	-	4,435.8	- [10]
15.	Post-Retirement True-Up V/A	2015 PTUVA	(880.1)	(17.0)	(880.1)	(21.8) [11]
16.	Constant Dollar Net Salvage Adjustment D/A	2016 CDNSADA	42,042.2	-	-	- [12]
17.	Energy East Consultation Costs D/A	2015 EECCDA	157.5	0.7	157.5	1.3 [13]
18.	Greenhouse Gas Emissions Impact D/A	2016 GGEIDA	127.5	0.4	-	- [14]
19.	Total non commodity Related Accounts		127,036.7	99.4	3,574.2	117.0
	Commodity Related Accounts					
20.	Transactional Services D/A	2015 TSDA	(9,074.8)	(74.9)	(9,074.8)	(124.7) [15]
21.	Storage and Transportation D/A	2015 S&TDA	4,771.4	46.0	4,771.4	72.4 [15]
22.	Unaccounted for Gas V/A	2015 UAFVA	1,302.9	5.2	1,302.9	12.4 [16]
23.	Unabsorbed Demand Cost D/A	2015 UDCDA	65,834.3	432.4	65,834.3	794.2 [17]
24.	Total commodity related accounts		62,833.8	408.7	62,833.8	754.3
25.	Total Deferral and Variance Accounts		189,870.5	508.1	66,408.0	871.3

Notes:

1. The final 2014 DSMVA, LRAM, and SSMVA balances to be cleared will be those approved within the EB-2015-0267 proceeding, which was filed October 30, 2015.
2. Clearance of the 2015 DSMVA will be requested through a separate application at a later date.
3. DRA evidence is found at Exhibit C, Tab 1, Schedule 8.
4. Clearance of the balance that was recorded in 2015 MGPDA is not being requested at this time. As was indicated in the EB-2015-0114 proceeding, the balance in the 2015 MGPDA was transferred to the 2016 MGPDA.
5. EPESDA evidence is found at Exhibit C, Tab 1, Schedule 11.
6. The clearance amount associated with the 2015 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 7.
7. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
8. Evidence within the B-series of exhibits provides details of Enbridge's 2015 utility results and 2015 earnings sharing calculation.
9. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 10.
10. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 9.
11. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 6.
12. Clearance of the balance that was recorded in 2015 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-2015-0114, the balance was transferred to the 2016 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.
13. EECCDA evidence is found at Exhibit C, Tab 1, Schedule 12.
14. Clearance of the balance that was recorded in 2015 GGEIDA is not being requested at this time. The 2015 balance of $80.3 thousand was transferred to the 2016 GGEIDA and clearance will be requested at a later date.
15. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 3.
16. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 4.
17. UDCDA evidence is found at Exhibit C, Tab 1, Schedule 2.

2015 UNABSORBED DEMAND COST DEFERRAL ACCOUNT REQUESTED FOR CLEARANCE OCTOBER 1, 2016

2015 Unabsorbed Demand Cost Deferral Account (2015 UDCDA)

The purpose of the 2015 UDCDA is to record the actual cost consequences of unutilized contracted capacity contracted by the Company to meet its Peak Day requirements in 2015. A consequence of contracting for incremental long haul capacity is the possibility of unabsorbed demand charges.

Background

1. As part of its 2015 Application (EB-2014-0276), the Company requested the establishment of the 2015 UDCDA which was forecast to be $166.4 million (Exhibit D1, Tab 2, Schedule 1, Appendix A). That amount was based upon 82.5 PJ's of unutilized capacity. Enbridge committed to using its best efforts to mitigate the UDC that would be otherwise recorded in the 2015 UDCDA.

2. In March of 2015 Enbridge, through consultation with stakeholders, developed a UDC Management Plan. The plan, which can be found at EB-2014-0276, Exhibit N1, Tab 1, Schedule 2, was intended to provide more information to stakeholders about how Enbridge planned to manage UDC in 2015. The plan set out targeted capacity release amounts based upon, among other things, forecasted demand levels. Enbridge also committed to providing monthly updates to its UDC management outcomes that would identify underlying factors impacting its decisions.

Utilization of Capacity in 2015

3. The colder than forecasted weather experienced in the winter of 2015 allowed the Company to fully utilize its contracted long haul TCPL capacity (including forecast UDC) during the month of March to assist in meeting demand. During the month of March Enbridge personnel reviewed the projected demand for the month of April and also reviewed its summer injection schedule. This review led Enbridge to make the decision to utilize 150,000 GJ's per day of the previously forecasted unutilized capacity in April for Utility purposes and to release 26,370 GJ's per day for the month of April and 74,910 GJ's per day of the forecasted unutilized capacity for the summer (16.0 PJ's over the period April to October) into the market in an effort to generate revenues from third parties to offset the cost of the unutilized capacity. Enbridge released a further 0.3 PJ's in total during the month of April on a day to day basis.

4. In the subsequent months, similar discussions between Gas Supply and Gas Storage personnel were held 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. The injection strategy also included discussions regarding the management of the forecasted unutilized long haul capacity. The outcome of these discussions was the amount and timing of further capacity releases throughout the summer. This included whether or not to release capacity for the remaining summer season, for the month or on a daily basis.

Witnesses: J. Leblanc
D. Small

5. Seasonal type releases amounted to 4.9 PJ's for the May to October period, 7.7 PJ's for the June to October period, and 3.1 PJ's for the July to October period. Through a combination of monthly releases and releases on the day the Company was able to mitigate an additional 8.1 PJ's of unutilized capacity from May to October.

6. The original forecast had also assumed 6.0 PJ's and 6.2 PJ's of unutilized capacity in November and December respectively, however, the Company was able to utilize 9.2 PJ's of this capacity for Utility purposes and to successfully release 3.2 PJ's.

7. In summary, of the originally forecasted 82.5 PJ's of unutilized capacity, the Company was able to use 38.9 PJ's for Utility purposes and to avoid $80.0 million of potential UDC costs. The remaining 43.6 PJ's of unutilized capacity which carried a cost of $86.3 million was released into the marketplace generating $20.5 million in revenue from third parties which has been included in the 2015 UDCDA as an offset to the cost consequences of the unutilized capacity. The value of the released capacity in 2015 equated to approximately 23.8% of associated cost ($20.5 million divided by $86.3 million) compared to 2014 when the Company received $5.3 million for released capacity valued at $31.7 million or approximately 16.7%.

8. The attached 2015 UDC Report sets out numeric details of the Company's monthly demand, as well as the unutilized capacity per month (on a volume and cost basis) and the monthly amounts recovered from the release of the unutilized capacity into the market.

Witnesses: J. Leblanc
D. Small

2015 UNABSORBED DEMAND COST REPORT

Demand	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December		
PJ's	85.1	86.2	64.7	37.6	18.5	15.7	15.4	15.1	15.2	29.8	39.6	48.4	471.3	

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	2015 UDCDA	
UDCDA	-	-	-	6.6	7.9	12.0	14.0	11.9	13.4	14.7	-	5.7	86.3	
Revenue From Unutilized Capacity Released														
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)	
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)	
- Daily				(0.1)	(0.4)	(0.7)	(0.8)	(0.4)	(1.0)	(0.7)	-	(0.3)	(4.3)	
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.1	10.6	8.9	9.9	11.3	-	5.5	65.8	- amount to be cleared

Forecasted Monthly Unutilized Capacity
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.1	6.0	6.8	7.4	-	3.0	43.6
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	(1.7)	(0.6)	(1.5)	(2.0)	-	(3.0)	(11.2)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-

Witnesses: J. LeBlanc, D. Small

2015 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT, 2015 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT, REQUESTED FOR CLEARANCE OCTOBER 1, 2016

2015 Storage and Transportation Deferral Account (2015 S&TDA)

1. The purpose of the 2015 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 will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition the S&TDA will be used to record amounts received by the Company related to deferral account dispositions of other utilities' deferral accounts.

3. The balance in the 2015 S&TDA that the Company is proposing to collect from customers is $4.77 million plus interest.

2015 Transactional Services Deferral Account (2015 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.

Witnesses: J. Leblanc
D. Small

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 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 $ 12.0 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 2015 the Company was able to generate a total of $23.2 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, $ 9.07 million proposed to be cleared through the 2015 TSDA.

8. The transactions that Enbridge entered into in 2015 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

2015 TRANSACTIONAL SERVICES REVENUE

Item #		$ 000's
1.0	Storage Optimization	517.4
2.0	Transportation Optimization	22,727.1
3.0	Transactional Services Revenue	23,244.6
4.0	Ratepayer Portion of TS	20,920.1
5.0	Less Guarantee in Rates	12,000.0
6.1	TSDA sub-total	8,920.1
6.2	ETT Revenue - Rider H	154.7
6.0	TSDA Total	9,074.8

Witnesses: J. Leblanc
D. 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 2015 variance relative to historical Unaccounted-For Gas ("UAF") volumes.

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 control measurement variation and 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 2015 level of UAF was determined to be 88,438 10^3m^3 which represents 0.75% of total sendout. The variance of 6,919 10^3m^3, which is the difference between actual UAF volume and forecast UAF volume of 81,519 10^3m^3, underpins the $1.3 million account balance that is captured in the UAFVA.

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 2015 that would have contributed to a higher AF than recently experienced.

Witnesses: R. Cheung
C. Ho

6. UAF has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels especially in 2013 and 2014 (Table 1). Although temperature-compensated meters are used, the Company notes that the higher levels of UAF coincide with consecutively cold winters. Nevertheless, given the inherent volatility of UAF, the 2015 level falls within the 95% confidence interval, bounded by (17,701) 10^3m^3 and 153,998 10^3m^3 (Table 2).

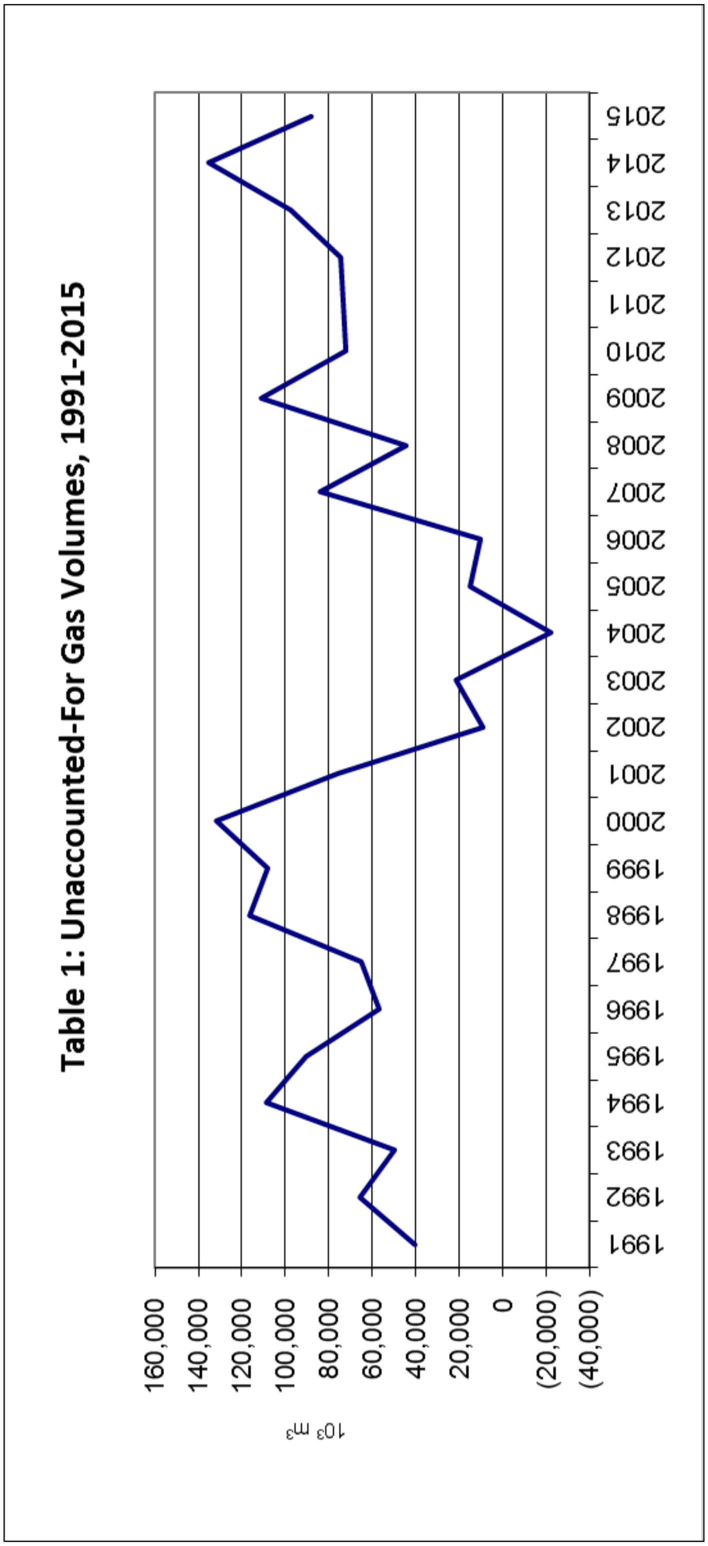

Table 1: Unaccounted-For Gas Volumes, 1991-2015

Table 2

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
2015	88,438
	1991-2014
Standard Deviation	41,493
Mean	68,149
Lower bound*	(17,701)
Upper bound*	153,998

*95% confidence interval with 23 degrees of freedom (number of observations-1)

Witnesses: R. Cheung
C. Ho

2015 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2015 Average Use True-up Variance Account ("AUTUVA") balance.

2. Table 1 of Appendix A details the calculations that result in the amount of $2.28 million that will constitute a refund to ratepayers. The refund is attributable to actual Rate 1 (residential) and Rate 6 average uses being higher than 2015 forecast levels.

3. Higher weather-normalized average use is primarily attributable to lower actual natural gas prices in 2015 than was forecast. Lower gas prices have been shown to increase consumption for both Rate 1 and Rate 6 customers.

4. 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.

Witnesses: R. Cheung
C. Ho

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 2015 DSM activities will not be available until a later date, the 2015 Board Approved Budget DSM volumes are used as an estimate of 2015 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2015 LRAM amounts which will be filed at a later date will exclude the impact of Rate 1 and Rate 6 customers.

Witnesses: R. Cheung
C. Ho

TABLE 1
2015 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Exhibit Reference:	EB-2014-0276, 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	2015 Budget Annual Use (m^3)	2015 Normalized Actual Annual Use (m^3)	Normalized Usage Variance (m^3)	Budget Customer Meters	Normalized Volumetric Variance (10^6m^3)	2015 DSM Budget (10^6m^3)	2015 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	2,419	2,427	9	1,933,935	16.8	(0.7)	(0.7)	0.0	16.8	0.0513	0.86
6	28,341	28,600	259	164,631	42.7	(19.5)	(19.5)	0.0	42.7	0.0332	1.42
Total					59.5	(20.2)	(20.2)	0.0	59.5		2.28

Witnesses: R. Cheung
C. Ho

2015 POST-RETIREMENT TRUE-UP VARIANCE ACCOUNT (PTUVA)

1. In accordance with the EB-2014-0276 Final Accounting Order, Appendix A, page 23, the purpose of PTUVA is to record the differences between the 2015 forecast pension and post-employment benefit expenses of $37.3 million and the actual pension and post-employment benefit expenses (both determined on an accrual basis).

2. As of December 31, 2015 the actual pension and post-employment benefit ("OPEB") expense was $37.6 million, as calculated by Mercer. A breakdown of the $37.6 million is as follows:

	$ million
Registered Pension Plan	29.1
Supplementary Executive Retirement Plan	0.5
Senior Supplementary Executive Retirement Plan	(0.1)
Supplementary Pension Plan	1.7
Defined contribution	0.9
Total pension expense	32.1
OPEB expense	5.5
Total pension and OPEB expense	37.6

3. Please refer to Appendix 1 for an extract of the 2015 Final Accounting Mercer Reports that supports the figures above.

4. Therefore, included within the 2015 PTUVA balance is a $0.3 million recoverable amount pertaining to 2015, representing the difference between the Board-Approved forecast of $37.3 million and the actual expense of $37.6 million.

Witnesses: J. Barradas
J. Shem

5. Also included within the 2015 PTUVA balance is a $1.2 million refundable amount transferred from the 2014 PTUVA. The balance transferred from the 2014 PTUVA was the balance in excess of $5 million, which in accordance with the 2014 PTUVA's scope, as approved within the EB-2012-0459 Final Accounting Order, Appendix A, page 24, was to be transferred to the 2015 PTUVA, as the maximum PTUVA amount that can be cleared annually is $5 million. Therefore, within this proceeding the Company is requesting clearance of a net refundable amount of $0.9 million, representing $0.3 million recoverable balance in relation to 2015 pension and OPEB amounts, and a residual $1.2 million refundable amount in relation to 2014 pension and OPEB amounts.

MERCER

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2015
US GAAP - January 18, 2016
Enbridge Gas Distribution Pension Plans - EGD RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
E. Reconciliation of amounts recognized in statement of financial position				
Initial net asset(obligation)	-	-	-	-
Prior service credit (cost)	-	-	-	-
Net gain (loss)	(274,472,300)	(4,837,500)	(2,203,000)	(281,512,800)
Accumulated other comprehensive income (loss)	(274,472,300)	(4,837,500)	(2,203,000)	(281,512,800)
Accumulated contributions in excess of net periodic benefit cost	222,125,500	1,107,500	(626,000)	222,607,000
Net asset (obligation) recognized in statement of financial position	(52,346,800)	(3,730,000)	(2,829,000)	(58,905,800)
F. Components of net periodic benefit cost				
Service cost	32,271,200	923,700	915,100	34,110,000
Interest cost	38,676,200	746,100	459,800	39,882,100
Expected return on plan assets	(59,829,200)	(990,900)	(582,400)	(61,402,500)
Amortization of initial net obligation (asset)	-	-	-	-
Amortization of prior service cost	-	-	-	-
Amortization of net (gain) loss	18,081,300	324,100	150,700	18,556,100
Net periodic benefit cost	29,199,500	1,003,000	943,200	31,145,700
Headcounts for expense[1]				
EGD RPP - DB service cost provision	1,999	77	79	2,155
[1] Note the 2015 expense is based on headcount as at December 31, 2013				
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	(39,383,600)	(922,600)	(762,200)	(41,068,400)
Amounts recognized as a component of net periodic benefit cost				
Amortization or curtailment recognition of prior service credit (cost)	-	-	-	-
Amortization or settlement recognition of net gain (loss)	(18,081,300)	(324,100)	(150,700)	(18,556,100)
Total recognized in other comprehensive loss (income)	(57,464,900)	(1,246,700)	(912,900)	(59,624,500)
Total recognized in net periodic benefit and other comprehensive loss (income)	(28,265,400)	(243,700)	30,300	(28,478,800)
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year				
Initial net asset (obligation)	-	-	-	-
Prior service credit (cost)	-	-	-	-
Net gain (loss)	(13,610,600)	(228,600)	(79,100)	(13,918,300)

Witnesses: J. Barradas, J. Shem

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2015
US GAAP - January 18, 2016
Enbridge Inc. Pension Plans - EI RPP

	Enbridge Inc.	Enbridge Pipelines Inc.	Enbridge Employee Services Canada 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
E. Reconciliation of amounts recognized in statements of financial position												
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(1,300)	-	(38,300)	-	(300)	(500)	(300)	-	(300)	-	-	(41,000)
Net gain (loss)	(31,082,900)	-	(169,777,300)	-	(937,500)	(1,494,300)	(4,454,500)	(6,857,600)	(1,967,900)	(67,800)	(1,044,500)	(217,684,300)
Accumulated other comprehensive income (loss)	(31,084,200)	-	(169,815,600)	-	(937,800)	(1,494,800)	(4,454,800)	(6,857,600)	(1,968,200)	(67,800)	(1,044,500)	(217,725,300)
Accumulated contributions in excess of net periodic benefit cost	16,478,500	-	94,763,000	-	955,600	1,750,500	773,200	349,800	2,960,300	75,600	193,600	118,300,100
Net asset (obligation) recognized in statement of financial position	(14,605,700)	-	(75,052,600)	-	17,800	255,700	(3,681,600)	(6,507,800)	992,100	7,800	(850,900)	(99,425,200)
F. Components of net periodic benefit cost												
Service cost	17,880,100	36,054,900	25,753,500	1,387,200	121,300	402,800	2,925,900	1,575,100	-	-	1,097,600	87,198,400
Interest cost	4,616,400	14,163,100	10,116,500	363,000	328,900	253,200	842,200	450,800	253,200	5,000	183,500	31,575,800
Expected return on plan assets	(7,161,300)	(21,045,100)	(15,032,200)	(476,800)	(478,400)	(447,000)	(1,140,700)	(551,800)	(470,900)	(9,000)	(279,300)	(47,092,500)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	5,000	89,300	63,800	-	1,000	2,000	1,000	-	1,000	-	-	163,100
Amortization of net (gain) loss	2,150,500	7,015,200	5,010,900	193,100	92,500	97,600	395,800	246,800	134,900	3,900	71,500	15,412,700
Net periodic benefit cost	17,490,700	36,277,400	25,912,500	1,466,500	65,300	308,600	3,024,200	1,720,900	(81,800)	(100)	1,073,300	87,257,500
Headcounts for expense[1]												
EI RPP - DB service cost provision (prior to Project Capture)	547	2,188	-	104	4	10	121	25	-	-	33	3,032
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	(6,286,200)	-	(39,197,000)	-	(670,100)	(202,100)	(2,423,900)	(786,600)	(375,400)	-	(197,900)	(50,139,200)
Amounts recognized as a component of net periodic benefit cost												
Amortization or curtailment recognition of prior service credit (cost)	(5,000)	(89,300)	(63,800)	-	(1,000)	(2,000)	(1,000)	-	(1,000)	-	-	(163,100)
Amortization or settlement recognition of net gain (loss)	(2,150,500)	(7,015,200)	(5,010,900)	(193,100)	(92,500)	(97,600)	(395,800)	(246,800)	(134,900)	(3,900)	(71,500)	(15,412,700)
Total recognized in other comprehensive loss (income)	(8,441,700)	(7,104,500)	(44,271,700)	(193,100)	(763,600)	(301,700)	(2,820,700)	(1,033,400)	(511,300)	(3,900)	(269,400)	(65,715,000)
Total recognized in net periodic benefit and other comprehensive loss (income)	9,049,000	29,172,900	(18,359,200)	1,273,400	(698,300)	6,900	203,500	687,500	(593,100)	(4,000)	803,900	21,542,500
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year												
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(1,300)	-	(38,300)	-	(300)	(500)	(300)	-	(300)	-	-	(41,000)
Net gain (loss)	(1,452,900)	-	(7,936,100)	-	(43,800)	(69,800)	(208,200)	(320,600)	(92,000)	(3,200)	(48,800)	(10,175,400)
H. Weighted-average assumptions to determine benefit obligations												
Discount rate	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%
Rate of compensation increase	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%	3.90%
Measurement date	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015
I. Assumptions to determine net cost												
Discount rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on assets	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Rate of compensation increase	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%	4.40%

[1] Note the 2015 expense is based on headcount as at December 31, 2013

Witnesses: J. Barradas, J. Shem

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Disclosure Information by Plan for Fiscal Year Ending December 31, 2015
US GAAP - January 18, 2016
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.		Retirement Plan for the Employees of Enbridge Inc. and Affiliates		The Enbridge Supplemental Pension Plan (without CGT Assets)		All Plans	
Fiscal year ending on	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014
C. Reconciliation of funded status												
1. Fair value of plan assets	937,095,800	930,244,200	17,022,900	17,284,300	8,125,900	8,194,400	727,144,300	645,412,200	196,809,100	185,770,800	1,886,198,000	1,786,905,900
2. Benefit obligations	996,001,600	1,017,628,800	15,301,600	16,076,600	4,082,000	4,334,200	826,569,500	799,430,300	222,236,500	219,567,200	2,064,191,200	2,057,037,100
3. Funded status (plan assets less benefit obligations)	(58,905,800)	(87,384,600)	1,721,300	1,207,700	4,043,900	3,860,200	(99,425,200)	(154,018,100)	(25,427,400)	(33,796,400)	(177,993,200)	(270,131,200)
4. Contributions and distributions made by company from measurement date to fiscal year end	-	-	-	-	-	-	-	-	-	-	-	-
5. Net asset (obligation) recognized in statement of financial position	(58,905,800)	(87,384,600)	1,721,300	1,207,700	4,043,900	3,860,200	(99,425,200)	(154,018,100)	(25,427,400)	(33,796,400)	(177,993,200)	(270,131,200)
D. Amounts recognized on the consolidated balance sheet position consists of												
1. Noncurrent assets	-	-	1,721,300	1,207,700	4,043,900	3,860,200	-	-	-	-	5,765,200	5,067,900
2. Current liabilities	-	-	-	-	-	-	-	-	-	-	-	-
3. Noncurrent liabilities	(58,905,800)	(87,384,600)	-	-	-	-	(99,425,200)	(154,018,100)	(25,427,400)	(33,796,400)	(183,758,400)	(275,199,100)
4. Net asset (obligation) recognized in statement of financial position	(58,905,800)	(87,384,600)	1,721,300	1,207,700	4,043,900	3,860,200	(99,425,200)	(154,018,100)	(25,427,400)	(33,796,400)	(177,993,200)	(270,131,200)
E. Reconciliation of amounts recognized in statement of financial position												
1. Initial net asset(obligation)	-	-	-	-	-	-	-	-	-	-	-	-
2. Prior service credit (cost)	-	-	-	-	-	-	(41,000)	(204,100)	(18,100)	(19,900)	(59,100)	(224,000)
3. Net gain (loss)	(281,512,800)	(341,137,300)	(3,020,200)	(3,883,300)	337,900	244,600	(217,684,300)	(283,236,200)	(76,651,800)	(89,748,300)	(578,531,200)	(717,760,500)
4. Accumulated other comprehensive income (loss)	(281,512,800)	(341,137,300)	(3,020,200)	(3,883,300)	337,900	244,600	(217,726,300)	(283,440,300)	(76,669,900)	(89,768,200)	(578,590,300)	(717,984,500)
5. Accumulated contributions in excess of net periodic benefit cost	222,607,000	253,752,700	4,741,500	5,091,000	3,706,000	3,615,600	118,300,100	129,422,200	51,242,500	55,971,800	400,597,100	447,853,300
6. Net asset (obligation) recognized in statement of financial position	(58,905,800)	(87,384,600)	1,721,300	1,207,700	4,043,900	3,860,200	(99,425,200)	(154,018,100)	(25,427,400)	(33,796,400)	(177,993,200)	(270,131,200)
F. Components of net periodic benefit cost												
1. Service cost	34,110,000	23,500,700	-	-	-	-	87,198,400	55,044,100	15,146,200	9,913,200	136,454,600	88,458,000
2. Interest cost	39,882,100	41,509,600	623,400	721,800	165,600	219,000	31,575,800	28,688,100	8,665,700	8,177,400	80,912,600	79,315,900
3. Expected return on plan assets	(61,402,500)	(56,905,600)	(542,200)	(530,900)	(256,000)	(248,200)	(47,092,500)	(39,577,900)	(10,129,200)	(9,282,000)	(119,422,400)	(106,544,600)
4. Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-	-
5. Amortization of prior service cost	-	-	-	-	-	-	163,100	163,100	1,800	1,800	164,900	164,900
6. Amortization of net (gain) loss	18,556,100	15,630,400	423,400	369,000	-	-	15,412,700	7,344,500	5,155,300	3,345,400	39,547,500	26,689,300
7. Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-
8. Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-
9. Special termination benefit recognized	-	-	-	-	-	-	-	-	-	-	-	-
10. Net periodic benefit cost	31,145,700	23,735,100	504,600	559,900	(90,400)	(29,200)	87,257,500	51,661,900	18,839,800	12,155,800	137,657,200	88,083,500

Witnesses: J. Barradas, J. Shem

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2015

US GAAP - January 16, 2018

Enbridge Inc. Pension Plans - EI SPP

	Enbridge Inc.	Enbridge Pipelines Inc.	Enbridge Employee Services Canada 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.	Gazifere Inc.	Tidal Energy Marketing Inc.	Total
E. Reconciliation of amounts recognized in statement of financial position													
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	(18,100)	-	-	-	-	-	-	-	-	-	-	-	(18,100)
Net gain (loss)	(45,487,800)	-	(22,751,500)	-	(150,400)	(1,265,900)	(280,500)	(242,000)	(5,579,300)	(147,100)	(19,500)	(727,800)	(76,651,800)
Accumulated other comprehensive income (loss)	(45,505,900)	-	(22,751,500)	-	(150,400)	(1,265,900)	(280,500)	(242,000)	(5,579,300)	(147,100)	(19,500)	(727,800)	(76,669,900)
Accumulated contributions in excess of net periodic benefit cost	33,633,600	-	6,850,300	-	314,000	3,870,600	(345,100)	188,900	5,875,300	439,700	10,700	404,500	51,242,500
Net asset (obligation) recognized in statement of financial position	(11,872,300)	-	(15,901,200)	-	163,600	2,604,700	(625,600)	(53,100)	296,000	292,600	(8,800)	(323,300)	(25,427,400)
F. Components of net periodic benefit cost													
Service cost	6,542,400	3,684,300	2,631,700	34,000	-	331,900	72,500	32,000	1,486,600	-	-	330,800	15,146,200
Interest cost	4,737,500	1,723,900	1,231,300	7,100	29,500	220,200	40,900	6,300	615,700	-	-	53,300	8,665,700
Expected return on plan assets	(6,344,200)	(1,409,100)	(1,006,500)	(4,500)	(40,100)	(426,200)	(12,900)	(11,500)	(806,000)	(15,500)	-	(52,700)	(10,129,200)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	1,800	-	-	-	-	-	-	-	-	-	-	-	1,800
Amortization of net (gain) loss	2,658,600	1,107,200	790,900	7,800	16,300	89,700	29,700	8,000	394,000	7,800	-	45,300	5,155,300
Net periodic benefit cost	7,596,100	5,106,300	3,647,400	44,400	5,700	215,600	130,200	34,800	1,690,300	(7,700)	-	376,700	18,839,800
Headcounts for expense (prior to Project Capture)[1]													
EI SPP (Only Senior Management Employees)	77	91	-	1	-	5	1	-	36	-	-	5	216
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	1,860,500	-	(8,394,600)	-	(116,700)	(206,700)	(206,300)	(15,800)	(885,200)	19,500	19,500	(15,400)	(7,941,200)
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)	(2,658,600)	(1,107,200)	(790,900)	(7,800)	(16,300)	(89,700)	(29,700)	(8,000)	(394,000)	(7,800)	-	(45,300)	(5,155,300)
Total recognized in other comprehensive loss (income)	(799,900)	(1,107,200)	(9,185,500)	(7,800)	(133,000)	(296,400)	(236,000)	(23,800)	(1,279,200)	11,700	19,500	(60,700)	(13,098,300)
Total recognized in net periodic benefit and other comprehensive loss (income)	6,796,200	3,999,100	(5,538,100)	36,600	(127,300)	(80,800)	(105,800)	11,000	411,100	4,000	19,500	316,000	5,741,500
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)	(2,437,700)	-	(1,219,300)	-	(8,100)	(67,800)	(15,000)	(13,000)	(299,000)	(7,900)	(1,000)	(39,000)	(4,107,800)
H. Weighted-average assumptions to determine benefit obligations													
Discount rate	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%
Rate of compensation increase	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.90%	3.68%
Measurement date	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015	31-Dec-2015
I. Assumptions to determine net cost													
Discount rate	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%		4.00%	4.00%
Expected return on assets	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%	5.40%
Rate of compensation increase	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%	4.33%

[1] Note the 2015 expense is based on headcount as at December 31, 2013

Witnesses: J. Barradas, J. Shem

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2015
US GAAP - January 18, 2016
Enbridge Gas Distribution Pension Plans - EGD RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
P. Reconciliation of net (gain) loss				
Amount as disclosed as of prior year end	331,937,200	6,084,200	3,115,900	341,137,300
Amounts recognized as a component of net periodic benefit cost				
Amortization	(18,081,300)	(324,100)	(150,700)	(18,556,100)
Effect of settlement	-	-	-	-
Total amount recognized as a component of net periodic benefit cost	(18,081,300)	(324,100)	(150,700)	(18,556,100)
Changes in plan assets and benefit obligations recognized in other comprehensive income				
Liability experience	(52,026,200)	(1,125,200)	(882,900)	(54,034,300)
Asset experience	12,642,600	202,600	120,700	12,965,900
Effect of curtailment	-	-	-	-
Extraordinary event that adjusts assets	-	-	-	-
Total amount recognized as a change in plan assets and benefit obligations	(39,383,600)	(922,600)	(762,200)	(41,068,400)
Other changes (adjustment to accumulated comprehensive income, retained earnings)				
Plan combinations	-	-	-	-
Adjustment to match local books	-	-	-	-
Difference between prior year end and beginning of current year	-	-	-	-
Difference between calculated year-end gain/loss and amount using events that occurred during the year	-	-	-	-
Total amount recognized as other change in accumulated other comprehensive income	-	-	-	-
Exchange rate adjustment	-	-	-	-
Amount at end of year	274,472,300	4,837,500	2,203,000	281,512,800
Actual net return on assets assuming middle of period cash flows	5.32%	5.43%	5.35%	5.33%
Q. DC Current service cost	915,800	57,300	38,700	1,011,800
Projected DC current service cost for fiscal year ending:				
31-Dec-2016 :	954,800	60,000	40,300	1,055,100
31-Dec-2017 :	987,600	62,000	41,700	1,091,300
31-Dec-2018 :	1,021,500	64,100	43,100	1,128,700
31-Dec-2019 :	1,056,500	66,300	44,600	1,167,400
31-Dec-2020 :	1,092,700	68,600	46,100	1,207,400
31-Dec-2021 :	1,130,200	71,000	47,700	1,248,900
31-Dec-2022 :	1,169,000	73,400	49,400	1,291,800
31-Dec-2023 :	1,209,100	75,900	51,100	1,336,100
31-Dec-2024 :	1,250,600	78,500	52,800	1,381,900
31-Dec-2025 :	1,293,500	81,200	54,600	1,429,300

Witnesses: J. Barradas, J. Shem

	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)	(1,746,000)	(29,000)	(13,000)	(1,788,000)
Net gain (loss)	(7,006,200)	(746,000)	14,000	(7,738,200)
Accumulated other comprehensive income (loss)	(8,752,200)	(775,000)	1,000	(9,526,200)
Accumulated contributions in excess of net periodic benefit cost	(96,663,800)	(1,281,000)	(1,271,000)	(99,215,800)
Net amount [surplus (deficit)] recognized in statement of financial position	(105,416,000)	(2,056,000)	(1,270,000)	(108,742,000)
Components of net periodic benefit cost				
Service cost	1,339,000	54,000	67,000	1,460,000
Interest cost	4,086,000	77,000	49,000	4,212,000
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	5,528,000	133,000	117,000	5,778,000
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	(439,000)	21,000	(83,000)	(501,000)
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)	(542,000)	19,000	(84,000)	(607,000)
Total recognized in net periodic benefit and other comprehensive loss (income)	4,986,000	152,000	33,000	5,171,000
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-2014-0276 Final Accounting Order, the Board approved the 2015 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 2015, the Company has included for recovery within the 2015 GDARIDA, the 2015 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. Within Enbridge’s Clearance of 2013 Deferral and Variance Accounts and 2012 DSM Related Accounts proceeding, EB-2014-0195, 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. As was indicated within that proceeding, 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 Customized Incentive Regulation plan approved in EB-2012-0459. 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.

4. Consistent with what was indicated within EB-2014-0195, as part of Enbridge's 2014 Earnings Sharing Mechanism and Deferral Account Clearance proceeding, EB-2015-0122, at Exhibit C, Tab 1, Schedule 7, the Company requested and received approval to recover the 2014 revenue requirement resulting from the LICSR changes.

5. As mentioned above, within this proceeding the Company has included for recovery within the 2015 GDARIDA, the 2015 revenue requirement, determined through a cost of service type calculation, which results from the LICSR changes. The Company is proposing to recover from ratepayers $0.295 million as part of the requested one time rate rider adjustment in October 2016, 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 2015 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 2015 actual required capital structure within the 2015 revenue requirement calculation. The approved 2013 and 2014 revenue requirement amounts credited to and recovered from ratepayers as part of the EB-2014-0195 and EB-2015-0122 proceedings, are also shown for continuity.

UTILITY CAPITAL STRUCTURE
2015 GDARIDA IMPACTS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		2013 Actual Capital Structure			2014 Actual Capital Structure			2015 Actual Capital Structure		
Line No.		Component	Indicated Cost Rate	Return Component	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	58.78	5.15	3.03
2.	Short-term debt	5.51	1.11	0.06	4.32	1.38	0.06	3.25	1.32	0.04
3.		61.67		3.34	61.87		3.17	62.03		3.07
4.	Preference shares	2.33	2.40	0.06	2.13	2.40	0.05	1.97	2.24	0.04
5.	Common equity	36.00	8.93	3.21	36.00	9.36	3.37	36.00	9.30	3.35
6.	Required Return on Rate Base	100.00		6.61	100.00		6.59	100.00		6.46

	($000's)	2013	2014	2015
7.	Ontario Utility Income	70.9	(63.7)	(181.5)
8.	Rate base	238.4	736.0	550.0
9.	Indicated rate of return	29.74 %	(8.65)%	(33.00)%
10.	(Def.) / suff. in rate of return	23.13 %	(15.24)%	(39.46)%
11.	Net (def.) / suff.	55.1	(112.2)	(217.0)
12.	Gross (def.) / suff.	75.0	(152.7)	(295.2)

Witnesses: D. McIlwraith
R. Small

UTILITY RATE BASE
2015 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015
	Property, plant, and equipment			
1.	Cost or redetermined value	260.1	876.3	876.3
2.	Accumulated depreciation	(21.7)	(140.3)	(326.3)
3.		238.4	736.0	550.0
	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	550.0

Witnesses: D. McIlwraith
R. Small

UTILITY INCOME
2015 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015
	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	186.0
10.	Municipal and other taxes	-	-	-
11.	Total costs and expenses	47.3	186.0	186.0
12.	Utility income before inc. taxes	(47.3)	(186.0)	(186.0)
	Income taxes			
13.	Excluding interest shield	(116.1)	(116.1)	-
14.	Tax shield on interest expense	(2.1)	(6.2)	(4.5)
15.	Total income taxes	(118.2)	(122.3)	(4.5)
16.	Ontario utility net income	70.9	(63.7)	(181.5)

Witnesses: D. McIlwraith
R. Small

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2015 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015
1.	Utility income before income taxes	(47.3)	(186.0)	(186.0)
	Add Backs			
2.	Depreciation and amortization	47.3	186.0	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	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	550.0
27.	Return component of debt	3.34%	3.17%	3.07%
28.	Interest expense	8.0	23.3	16.9
29.	Combined tax rate	26.500%	26.500%	26.500%
30.	Income tax credit	(2.1)	(6.2)	(4.5)
31.	Total income taxes	(118.2)	(122.3)	(4.5)

Witnesses: D. McIlwraith
R. Small

UTILITY REVENUE REQUIREMENT
2015 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015
	Cost of capital			
1.	Rate base	238.4	736.0	550.0
2.	Required rate of return	6.61%	6.59%	6.46%
3.	Cost of capital	15.8	48.5	35.5
	Cost of service			
4.	Gas costs	-	-	-
5.	Operation and Maintenance	-	-	-
6.	Depreciation and amortization	47.3	186.0	186.0
7.	Municipal and other taxes	-	-	-
8.	Cost of service	47.3	186.0	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)	(4.5)
14.	Income taxes on earnings	(118.2)	(122.3)	(4.5)
	Taxes on (def) / suff.			
15.	Gross (def.) / suff.	75.0	(152.7)	(295.2)
16.	Net (def.) / suff.	55.1	(112.2)	(217.0)
17.	Taxes on (def.) / suff.	(19.9)	40.5	78.2
18.	Revenue requirement	(75.0)	152.7	295.2
	Revenue at existing Rates			
19.	Gas sales	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0
22.	Rounding adjustment	0.0	0.0	0.0
23.	Revenue at existing rates	0.0	0.0	0.0
24.	Gross revenue (def.) / suff.	75.0	(152.7)	(295.2)

Witnesses: D. McIlwraith
R. Small

2015 DEFERRED REBATE ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2016

1. The 2015 Deferred Rebate Account ("DRA") was approved by the Board within the EB-2014-0276 Final Accounting Order, at Appendix A, page 17. The description and scope of the 2015 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 $0.4 million recorded in the 2015 DRA and requested for clearance, reflects the outstanding amount resulting from the clearance of deferral and variance accounts which occurred during 2015, and the inability to locate all the intended customers. In April 2015, the Company cleared the 2013 deferral and variance accounts and the 2012 DSM related accounts which were approved within EB-2014-0195, as well as the 2013 DSM related accounts which were approved within EB-2014-0277. In October 2015, the 2014 deferral account balances were cleared, as approved within the EB-2015-0122 proceeding.

2016 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2016

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, second, and third or 2013, 2014, and 2015 installments of $4.436 million each (1/20 of $88.716 million), were approved for recovery within the EB-2013-0046, EB-2014-0195, and EB-2015-0122 proceedings.

3. Enbridge is now requesting recovery of the fourth, or 2016 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.

Witnesses: J. Barradas
R. Small

2013, 2014 AND 2015 CUSTOMER CARE CIS RATE SMOOTHING
DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2016

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 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, EB-2012-0459 Final Accounting Order, and EB-2014-0276 Final Accounting Order, the Board approved of the 2013, 2014 and 2015 CCCISRSDAs. The principal balance recorded within each of the 2013, 2014 and 2015 accounts ($4.6 million, $2.9 million and $1.1 million), reflects each year's approved variance between the forecast customer care and CIS costs and the amount incorporated into rates.

5. 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.

6. Within this proceeding, the Company is requesting clearance of the interest balances on the 2013, 2014, and 2015 CCCISRSDAs, in the amounts of $68.1 thousand, $43.1 thousand, and $20.1 thousand as shown in Exhibit C, Tab 1, Schedule 1, page 3. The annual clearance of accumulated interest amounts over 2013 to 2018, the term covered by the EB-2011-0226 Settlement Agreement, is consistent with the approach approved in that case.

2015 ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2016

1. The 2015 Electric Program Earnings Sharing Deferral Account ("EPESDA") was approved by the Board within the EB-2014-0276 Final Accounting Order, at Appendix A, page 31. The description and scope of the 2015 account, consistent with prior fiscal years, was to track and account for the ratepayer share of all net revenues generated by DSM services provided for electric CDM activities. The ratepayer share being 50% of net revenues, using fully allocated costs, as was determined in the DSM guidelines proceeding EB-2008-0346.

2. The ($0.1) million recorded in the 2015 EPESDA and requested for clearance reflects pay for performance net revenues from participating LDC's for the delivery of the High Performance New Construction (HPNC) program. Revenues were generated from the period January 1st 2015 to March 31st, 2015, which was the contractual delivery end point of the program. The HPNC program was a new construction conservation program offering financial incentives for qualifying participants and design decision makers to encourage the implementation of electric energy efficiency measures in qualifying new construction projects. The program was collaboratively delivered by Enbridge Gas Distribution and Union Gas on behalf of 23 individually contracted LDC's.

Witness: E. Reimer

2015 ENERGY EAST CONSULTATION COSTS DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE OCTOBER 1, 2016

1. The purpose of the 2015 Energy East Consultation Costs Deferral Account ("EECCDA") was to record the Energy East consultation costs as allocated by the Board. Enbridge's establishment of the account was approved by the Board, by letter dated June 13, 2014, within the EB-2013-0398 proceeding.

2. The Board undertook an Energy East consultation at the request of Ontario's Minister of Energy (by letter dated November 12, 2013). The Ontario Minister of Energy requested the Board to examine and report on TransCanada PipeLines Limited's proposed Energy East Pipeline from an Ontario perspective. The request contemplated that the Board would undertake consultations with Ontarians to understand the impacts of the project on natural gas consumers, local and Aboriginal communities, the natural environment and pipeline safety, and the economy. On August 13, 2015, the OEB submitted its Report to the Minister.

3. Through the EB-2013-0398 proceeding, the Board invoiced its costs in relation to the Energy East Consultation to all entities which are subject to the Board's cost assessment under section 26 of the Act, of which $157.5 thousand was allocated to Enbridge. These costs were recorded in the 2015 EECCDA.

4. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2015 EECCDA, in the amount of $157.5 thousand and $1.2 thousand respectively, as shown in Exhibit C, Tab 1, Schedule 1, page 3.

CLEARANCE OF 2015 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The Company is proposing to clear 2015 Deferral and Variance Account balances (as well as other balances set out at Appendix A to the Application – see Exhibit A, Tab 2, Schedule 1, Appendix A) to customers during the October and November 2016 billing cycles.

2. The unit rates for each type of service are shown at Exhibit C, Tab 2, Schedule 2, page 1. These unit rates will be applied to each customer's actual 2015 consumption volume for the period January 1, 2015 to December 31, 2015, and will be recovered or refunded as two equal billing adjustments in the months of October and November 2016.

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 2015 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 2015 consumption volumes for each rate class and each type of service.

4. The table on page 6 displays the bill adjustments in October and November 2016 for typical customers resulting from the clearance of the 2015 Deferral and Variance Account balances. These bill adjustments will be shown as a separate line item on customers' October and November 2016 bills.

Witnesses: J. Collier
A. Kacicnik
B. So

5. Although, the allocation of the balances within the Deferral and Variance Accounts to be cleared will be performed in the same manner as previous years, the Company would like to highlight proposed clearance methodology for the following three accounts: 1) Energy East Consultation Costs Deferral Account ("EECCDA"), which the Company is proposing to clear for the first time. 2) Electric Program Earnings Sharing Deferral Account ("EPESDA"), which did not have a balance in 2013 and 2014. 3) Unabsorbed Demand Cost ("UDCDA"), which constitutes the largest balance among all the 2015 Deferral and Variance Account balances.

<u>EECCDA:</u>

6. The EECCDA captures the Ontario Energy Board costs associated with consultations on TransCanada's ("TCPL") proposed Energy East Pipeline Project Board File No.: EB-2013-0398.

7. The Company contracts long haul Firm Transportation ("FT") capacity on TCPL to meet its annual demand. The proposed Energy East Pipeline Project could have an impact on the Company's transportation costs as well as capacity requirements on the TCPL system. Consequently, the consultations addressed concerns about costs and capacity constrains from Ontario gas utilities. To represent cost causality, the Company proposes to clear the balance of the EECCDA to all bundled customers (System gas and Western T – Service customers) who receive upstream transportation service from the Company based on the total bundled transportation deliveries allocation factor. This approach mimics how upstream transportation costs are recovered from customers in rates.

EPESDA:

8. The EPESDA was first approved by the Board within EB-2006-0034 and then annually as part of Accounting Orders such as in EB-2014-0276 Final Accounting Order, Appendix A, page 31. The purpose of the account was to track and account for the ratepayer share of all net revenues generated by DSM services provided for electric CDM activities.

9. Given that cost causality for the net revenues from DSM services provided for electric CDM activities is not readily identifiable; the Company proposes to clear the balance of the EPESDA to all customers based on the rate base factor under the Board-approved cost allocation and rate design methodology. The Board-approved this approach to disposition of EPESDA balance in EB-2006-0034.

UDCDA

10. As part of its 2015 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 2015, the associated UDC costs were debited to the UDCDA. Conversely, any revenues received from the release of the unutilized capacity were credited to the UDCDA.

11. 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 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 UDCDA 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). The Board-approved this approach to disposition of UDCDA balance in EB-2015-0122.

<u>OTHER:</u>

12. The Company is proposing to clear the 2015 balances in two equal installments since the total balance and bill adjustments are substantial relative to other years. In a similar proceeding (EB-2007-0615), the Ontario Energy Board directed the Company to clear the balance in two equal installments.

Witnesses: J. Collier
A. Kacicnik
B. So

UNIT RATE AND TYPE OF SERVICE: CLEARING IN OCTOBER AND NOVEMBER 2016

		COL.1 TOTAL (¢/m³)	COL. 2 October Unit Rate	COL. 3 November Unit Rate
Bundled Services:				
RATE 1	- SYSTEM SALES	0.8933	0.4466	0.4466
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.9869	0.4934	0.4934
	- WESTERN T-SERVICE	0.8933	0.4466	0.4466
RATE 6	- SYSTEM SALES	0.4661	0.2331	0.2331
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.5597	0.2799	0.2799
	- WESTERN T-SERVICE	0.4661	0.2331	0.2331
RATE 9	- SYSTEM SALES	(0.6787)	(0.3393)	(0.3393)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.5851)	(0.2925)	(0.2925)
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.4984	0.2492	0.2492
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.4984	0.2492	0.2492
RATE 110	- SYSTEM SALES	(0.0508)	(0.0254)	(0.0254)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0428	0.0214	0.0214
	- WESTERN T-SERVICE	(0.0508)	(0.0254)	(0.0254)
RATE 115	- SYSTEM SALES	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0519)	(0.0260)	(0.0260)
	- WESTERN T-SERVICE	(0.1455)	(0.0728)	(0.0728)
RATE 135	- SYSTEM SALES	(0.1747)	(0.0873)	(0.0873)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0811)	(0.0405)	(0.0405)
	- WESTERN T-SERVICE	(0.1747)	(0.0873)	(0.0873)
RATE 145	- SYSTEM SALES	(1.2781)	(0.6391)	(0.6391)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(1.1846)	(0.5923)	(0.5923)
	- WESTERN T-SERVICE	(1.2781)	(0.6391)	(0.6391)
RATE 170	- SYSTEM SALES	(0.3714)	(0.1857)	(0.1857)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.2778)	(0.1389)	(0.1389)
	- WESTERN T-SERVICE	(0.3714)	(0.1857)	(0.1857)
RATE 200	- SYSTEM SALES	0.2881	0.1440	0.1440
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3817	0.1908	0.1908
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000
Unbundled Services:				
RATE 125	- All	(0.1704)	(0.0852)	(0.0852)
	- Customer-specific ($)	$0		
RATE 300	- All	(2.6258)	(1.3129)	(1.3129)

DETERMINATION OF BALANCES TO BE CLEARED
FROM THE 2015 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	(9,074.8)	(124.7)	(9,199.5)
2.	UNACCOUNTED FOR GAS V/A	1,302.9	12.4	1,315.3
3.	STORAGE AND TRANSPORTATION D/A	4,771.4	72.4	4,843.8
4.	DEFERRED REBATE ACCOUNT	419.0	2.8	421.8
5.	DEMAND SIDE MANAGEMENT 2014	352.5	7.0	359.5
6.	LOST REVENUE ADJ MECHANISM 2014	(65.3)	(0.8)	(66.1)
7.	DEMAND SIDE MANAGEMENT INCENTIVE 2014	7,647.2	70.0	7,717.2
8.	ELECTRIC PROGRAM EARNINGS SHARING	(59.3)	(0.8)	(60.1)
9.	GAS DISTRIBUTION ACCESS RULE D/A 2015	295.2	0.0	295.2
10.	AVERAGE USE TRUE-UP V/A	(2,278.3)	(18.9)	(2,297.2)
11.	POST-RETIREMENT TRUE-UP V/A	(880.1)	(21.8)	(901.9)
12.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A		20.1	20.1
13.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A		43.1	43.1
14.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A		68.1	68.1
15.	ENERGY EAST CONSULTATIONS	157.5	1.3	158.8
16.	UNABSORBED DEMAND COST D/A	65,834.3	794.2	66,628.5
17.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8		4,435.8
18.	EARNINGS SHARING MECHANISM	(6,450.0)	(53.1)	(6,503.1)
19.	TOTAL	66,408.0	871.3	67,279.3

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	(9,199.5)	(8,841.4)			(129.6)	(228.5)				
2.	UNACCOUNTED FOR GAS V/A	1,315.3			1,315.3						
3.	STORAGE AND TRANSPORTATION D/A	4,843.8				1,753.5	3,090.3				
4.	DEFERRED REBATE ACCOUNT	421.8			421.8						
5.	DEMAND SIDE MANAGEMENT 2014	359.5							359.5		
6.	LOST REVENUE ADJ MECHANISM 2014	(66.1)							(66.1)		
7.	DEMAND SIDE MANAGEMENT INCENTIVE 2014	7,717.2							7,717.2		
8.	ELECTRIC PROGRAM EARNINGS SHARING	(60.1)									(60.1)
9.	GAS DISTRIBUTION ACCESS RULE D/A 2015	295.2								295.2	
10.	AVERAGE USE TRUE-UP V/A	(2,297.2)							(2,297.2)		
11.	POST-RETIREMENT TRUE-UP V/A	(901.9)									(901.9)
12.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A	20.1								20.1	
13.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A	43.1								43.1	
14.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A	68.1								68.1	
15.	ENERGY EAST CONSULTATIONS	158.8	158.8		0.0					0.0	
16.	UNABSORBED DEMAND COST D/A	66,628.5					66,628.5				
17.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8						0.0			4,435.8
18.	EARNINGS SHARING MECHANISM	(6,503.1)						0.0			(6,503.1)
19.	TOTAL	67,279.3	(8,682.6)	0.0	1,737.1	1,623.9	69,490.3	0.0	5,713.4	426.5	(3,029.3)
	ALLOCATION										
1.1	RATE 1	44,867.8	(4,446.5)	0.0	729.1	782.1	38,724.8	0.0	10,757.2	393.1	(2,072.1)
1.2	RATE 6	24,374.9	(3,647.2)	0.0	730.5	756.7	29,772.8	0.0	(2,405.9)	33.3	(865.3)
1.3	RATE 9	(2.2)	(0.3)	0.0	0.0	0.0	0.1	0.0	0.2	0.0	(2.3)
1.4	RATE 100	18.5	(3.5)	0.0	0.5	(0.0)	22.1	0.0	0.0	0.0	(0.6)
1.5	RATE 110	45.5	(240.1)	0.0	97.5	28.6	278.1	0.0	(94.6)	0.0	(23.9)
1.6	RATE 115	(316.1)	(50.2)	0.0	74.7	0.0	64.5	0.0	(392.6)	0.0	(12.6)
1.7	RATE 125	(16.9)	0.0	0.0	0.0	0.0	0.0	0.0	8.8	0.0	(25.7)
1.8	RATE 135	(94.9)	(39.2)	0.0	10.0	0.0	0.0	0.0	(64.1)	0.0	(1.6)
1.9	RATE 145	(937.6)	(19.7)	0.0	11.3	7.1	0.0	0.0	(929.1)	0.0	(7.3)
1.10	RATE 170	(1,208.8)	(112.3)	0.0	57.6	25.3	0.0	0.0	(1,170.0)	0.0	(9.5)
1.11	RATE 200	549.6	(123.7)	0.0	25.7	24.0	628.1	0.0	3.0	0.0	(7.6)
1.12	RATE 300	(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	(1.0)
1.		67,279.3	(8,682.6)	0.0	1,737.1	1,623.9	69,490.3	0.0	5,713.4	426.5	(3,029.3)

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 ($000)	SALES AND WBT ($000)	TOTAL SALES ($000)	TOTAL DELIVERIES ($000)	SPACE ($000)	DELIVE-RABILITY ($000)	DISTRIBUTION REV REQ (DRR) ($000)	DIRECT ($000)	NUMBER OF CUSTOMERS ($000)	RATE BASE ($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	40,716.5	(4,266.3)	0.0	665.1	713.4	35,323.4	0.0	9,812.3	358.6	(1,890.1)
	- 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	2,431.8			36.0	38.6	1,909.6	0.0	530.5	19.4	(102.2)
	- WBT	1,719.5	(180.2)		28.1	30.1	1,491.7	0.0	414.4	15.1	(79.8)
RATE 6	- SYSTEM SALES	13,506.9	(2,712.3)	0.0	422.8	438.0	17,232.4	0.0	(1,392.6)	19.3	(500.8)
	- 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	6,212.2			161.9	167.8	6,600.3	0.0	(533.4)	7.4	(191.8)
	- WBT	4,655.8	(934.9)		145.7	151.0	5,940.0	0.0	(480.0)	6.6	(172.6)
RATE 9	- SYSTEM SALES	(1.9)	(0.3)	0.0	0.0	0.0	0.1	0.0	0.2	0.0	(2.0)
	- 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	(0.2)			0.0	0.0	0.0	0.0	0.0	0.0	(0.3)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	18.0	(3.4)	0.0	0.5	(0.0)	21.5	0.0	0.0	0.0	(0.6)
	- 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	0.5	(0.1)		0.0	(0.0)	0.6	0.0	0.0	0.0	(0.0)
RATE 110	- SYSTEM SALES	(21.8)	(40.1)	0.0	6.2	1.8	17.8	0.0	(6.1)	0.0	(1.5)
	- 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	176.0			60.0	17.6	171.3	0.0	(58.3)	0.0	(14.7)
	- WBT	(108.6)	(200.1)		31.2	9.2	89.0	0.0	(30.3)	0.0	(7.7)
RATE 115	- SYSTEM SALES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(238.1)			66.9	0.0	57.7	0.0	(351.6)	0.0	(11.2)
	- WBT	(78.0)	(50.2)		7.8	0.0	6.7	0.0	(41.1)	0.0	(1.3)
RATE 135	- SYSTEM SALES	(4.1)	(2.2)	0.0	0.3	0.0	0.0	0.0	(2.2)	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	(21.7)			3.9	0.0	0.0	0.0	(25.0)	0.0	(0.6)
	- WBT	(69.1)	(37.0)		5.8	0.0	0.0	0.0	(36.9)	0.0	(0.9)
RATE 145	- SYSTEM SALES	(167.5)	(12.3)	0.0	1.9	1.2	0.0	0.0	(157.1)	0.0	(1.2)
	- 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	(669.1)			8.2	5.1	0.0	0.0	(677.2)	0.0	(5.3)
	- WBT	(101.0)	(7.4)		1.2	0.7	0.0	0.0	(94.7)	0.0	(0.7)
RATE 170	- SYSTEM SALES	(129.9)	(32.7)	0.0	5.1	2.2	0.0	0.0	(103.7)	0.0	(0.8)
	- 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	(763.4)			40.1	17.6	0.0	0.0	(814.6)	0.0	(6.6)
	- WBT	(315.5)	(79.5)		12.4	5.5	0.0	0.0	(251.8)	0.0	(2.0)
RATE 200	- SYSTEM SALES	380.7	(123.7)	0.0	19.3	18.0	470.5	0.0	2.3	0.0	(5.7)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	168.9			6.5	6.0	157.5	0.0	0.8	0.0	(1.9)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		(16.9)	0.0	0.0	0.0	0.0	0.0	0.0	8.8	0.0	(25.7)
RATE 300		(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	(1.0)
		67,279.3	(8,682.6)	0.0	1,737.1	1,623.9	69,490.3	0.0	5,713.4	426.5	(3,029.3)

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	0.8933	(0.0936)	0.0000	0.0146	0.0157	0.7750	0.0000	0.2153	0.0079	(0.0415)	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	0.9869			0.0146	0.0157	0.7750	0.0000	0.2153	0.0079	(0.0415)	0.0000
	- WESTERN T-SERVICE	0.8933	(0.0936)		0.0146	0.0157	0.7750	0.0000	0.2153	0.0079	(0.0415)	0.0000
RATE 6	- SYSTEM SALES	0.4661	(0.0936)	0.0000	0.0146	0.0151	0.5947	0.0000	(0.0481)	0.0007	(0.0173)	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	0.5597			0.0146	0.0151	0.5947	0.0000	(0.0481)	0.0007	(0.0173)	0.0000
	- WESTERN T-SERVICE	0.4661	(0.0936)		0.0146	0.0151	0.5947	0.0000	(0.0481)	0.0007	(0.0173)	0.0000
RATE 9	- SYSTEM SALES	(0.6787)	(0.0936)	0.0000	0.0146	0.0000	0.0204	0.0000	0.0713	0.0003	(0.6917)	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	(0.5851)			0.0146	0.0000	0.0204	0.0000	0.0713	0.0003	(0.6917)	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	0.4984	(0.0936)	0.0000	0.0146	(0.0000)	0.5947	0.0000	0.0000	0.0000	(0.0173)	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	0.4984	(0.0936)		0.0146	(0.0000)	0.5947	0.0000	0.0000	0.0000	(0.0173)	0.0000
RATE 110	- SYSTEM SALES	(0.0508)	(0.0936)	0.0000	0.0146	0.0043	0.0416	0.0000	(0.0142)	0.0000	(0.0036)	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	0.0428			0.0146	0.0043	0.0416	0.0000	(0.0142)	0.0000	(0.0036)	0.0000
	- WESTERN T-SERVICE	(0.0508)	(0.0936)		0.0146	0.0043	0.0416	0.0000	(0.0142)	0.0000	(0.0036)	0.0000
RATE 115	- SYSTEM SALES	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	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	(0.0519)			0.0146	0.0000	0.0126	0.0000	(0.0767)	0.0000	(0.0025)	0.0000
	- WESTERN T-SERVICE	(0.1455)	(0.0936)		0.0146	0.0000	0.0126	0.0000	(0.0767)	0.0000	(0.0025)	0.0000
RATE 135	- SYSTEM SALES	(0.1747)	(0.0936)	0.0000	0.0146	0.0000	0.0000	0.0000	(0.0934)	0.0000	(0.0023)	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	(0.0811)			0.0146	0.0000	0.0000	0.0000	(0.0934)	0.0000	(0.0023)	0.0000
	- WESTERN T-SERVICE	(0.1747)	(0.0936)		0.0146	0.0000	0.0000	0.0000	(0.0934)	0.0000	(0.0023)	0.0000
RATE 145	- SYSTEM SALES	(1.2781)	(0.0936)	0.0000	0.0146	0.0091	0.0000	0.0000	(1.1989)	0.0000	(0.0094)	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	(1.1846)			0.0146	0.0091	0.0000	0.0000	(1.1989)	0.0000	(0.0094)	0.0000
	- WESTERN T-SERVICE	(1.2781)	(0.0936)		0.0146	0.0091	0.0000	0.0000	(1.1989)	0.0000	(0.0094)	0.0000
RATE 170	- SYSTEM SALES	(0.3714)	(0.0936)	0.0000	0.0146	0.0064	0.0000	0.0000	(0.2964)	0.0000	(0.0024)	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	(0.2778)			0.0146	0.0064	0.0000	0.0000	(0.2964)	0.0000	(0.0024)	0.0000
	- WESTERN T-SERVICE	(0.3714)	(0.0936)		0.0146	0.0064	0.0000	0.0000	(0.2964)	0.0000	(0.0024)	0.0000
RATE 200	- SYSTEM SALES	0.2881	(0.0936)	0.0000	0.0146	0.0136	0.3560	0.0000	0.0017	0.0000	(0.0043)	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	0.3817			0.0146	0.0136	0.3560	0.0000	0.0017	0.0000	(0.0043)	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:												
RATE 125	- All	(0.1704)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0885	0.0000	(0.2589)	0.0000
	- Customer-specific **											0.0000
RATE 300	- All	(2.6258)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.7489	0.0000	(6.3747)	0.0000
	- Customer-specific **											

Notes:
* Unit Rates derived based on 2015 actual volumes

ENBRIDGE GAS DISTRIBUTION INC.
2015 DEFERRAL AND VARIANCE ACCOUNT CLEARING
BILL ADJUSTMENT IN OCTOBER AND NOVEMBER 2016 FOR TYPICAL CUSTOMERS

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Unit Rates			Bill Adjustment		
	GENERAL SERVICE	Annual Volume m^3	Sales cents/m^3	Ontario TS cents/m^3	Western TS cents/m^3	Sales Customers $	Ontario TS Customers $	Western TS Customers $
1.1	RATE 1 RESIDENTIAL							
1.2	Heating & Water Heating	2,400	0.4466	0.4934	0.4466	10.7	11.8	10.7
2.1	RATE 6 COMMERCIAL							
2.2	General Use	43,285	0.2331	0.2799	0.2331	101	121	101
	CONTRACT SERVICE							
3.1	RATE 100							
3.2	Industrial - small size	339,188	0.2492	0.0000	0.0000	845	-	-
4.1	RATE 110							
4.2	Industrial - small size, 50% LF	598,568	(0.0254)	0.0214	(0.0254)	(152)	128	(152)
4.5	Industrial - avg. size, 75% LF	9,976,121	(0.0254)	0.0214	(0.0254)	(2,535)	2,133	(2,535)
5.1	RATE 115							
5.2	Industrial - small size, 80% LF	4,471,609	0.0000	(0.0260)	(0.0728)	-	(1,161)	(3,253)
6.1	RATE 135							
6.2	Industrial - Seasonal Firm	598,567	(0.0873)	(0.0405)	(0.0873)	(523)	(243)	(523)
7.1	RATE 145							
7.2	Commercial - avg. size	598,568	(0.6391)	(0.5923)	(0.6391)	(3,825)	(3,545)	(3,825)
8.1	RATE 170							
8.2	Industrial - avg. size, 75% LF	9,976,121	(0.1857)	(0.1389)	(0.1857)	(18,524)	(13,855)	(18,524)

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

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 second Stakeholder Day on March 30, 2016 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

6. The materials noted above are filed within this proceeding for information purposes. Enbridge is not seeking any relief on these items.

STATUS OF GTA PROJECT

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.

1. Enbridge provided such information at the March 30, 2016 Stakeholder Day (please see pages 20 to 30 of the Stakeholder Day materials found at Exhibit D, Tab 3, Schedule 1).

2. As indicated at the Stakeholder Day, the project has experienced some timing delays and cost challenges due to the complexity of permiting in urban areas. The pipeline is currently energized and residual and closeout costs will continue to occur throughout 2016.

3. Some siting issues have also been experienced, which will delay the installation of the Buttonville and Jonesville stations. The Jonesville Station was relocated to the Ashtonbee site (EB-2016-0034) and will be in service Q4 2016. Buttonville Station will be built in 2017, contingent upon the successful acquisition of the necessary land.

4. The actual 2015 costs incurred versus forecast as at December 31, 2015 were $551.0 million versus the forecast of $359.7 million approved by the Board. This was due to increased construction costs.

5. The current approximate forecast of costs remaining to complete the project are approximately $182.4 million, for a total project cost of $922 million. This is higher than the forecast total project cost of $686.5 million that was presented to the Board.

Witness: S. Dodd

6. The overall cost increase is driven by a number of factors, including:

   1) escalation of construction bid price, relative to what was filed in EB 2012-0451;

   2) increased costs associated with greater construction complexity, relative to the design basis used to estimate the costs in EB 2012-0451; and

   3) increased project duration due to longer permit acquisition timelines.

7. The Company will file further evidence about the GTA project costs within the 2019 rebasing application, or such other proceeding where such evidence is relevant and required.

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 March 30, 2016 Stakeholder Day. (Please see pages 31 to 40 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 technology and business complexity involved with this project, whereby additional time was spent ensuring the design was correct and each component was sufficiently tested before commencing integration testing. Similar care will continue throughout the integration and user acceptance testing cycles to ensure that the final product is of high quality and safely supports Enbridge's emergency and non-emergency work. The project is expected to progress through 2016 and is anticipated to be in service by Q3, 2016, with a stabilization and warranty period to follow. This is a few months later than the intitial forecast that WAMS would go live by the end of 2015, which results in the transition from Envision continuing into 2016.

4. The actual costs incurred as at December 31, 2015 were $47.2 million versus the cumulative forecast of $62.5 million to the end of 2015 that was presented in the EB-2012-0459 proceeding. The current forecast of costs remaining to complete the project is approximately $32.5 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.

5. The cost variances to date are mostly the result of timing delays due to the competitive bid processes, technology and business complexities and quality assurance as noted above, which has delayed some of the spending initially planned for 2014 and 2015. The anticipated future cost variances are mostly due to the greater level of detail now understood as a result of the Design and Construct Phases.

Witnesses: W. Akkermans
B. Misra

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.

4. System Integrity and Reliability consists of programs, projects and activities focused on:
   - Maintaining the entire natural gas storage, transmission and distribution pressurized system at or above adopted standards for continued safe and effective operation (System Integrity);
   - Ensuring the dependable delivery of natural gas to Enbridge's customers and end-users (Reliability).

5. The Company undertook many initiatives in 2015 to continue to address known issues and proactively maintain a safe and reliable distribution and storage system. In 2014 and 2015, significant efforts were focused on:
   - Gaining a better understanding of the health and condition of assets as it pertains to risk determination and risk reduction
   - designing appropriate risk reduction strategies
   - developing risk based assessment methodologies
   - developing an asset management framework in order to make effective decisions in terms of prioritizing capital spend with the outcomes being spending the right money on the right asset at the right time.

6. As shown below within Table 1, Enbridge's actual System Integrity spend within 2015 was $134M versus the $135.1M which the Board approved within the EB- 2012-0459 proceeding.

ASSET CATEGORY	2015 Act	2015 IRM	2015 Variance
Mains	27,148	24,088	(3,060)
Services	24,744	25,021	277
Stations	23,823	26,442	2,619
Meters/Records/Envision	45,885	42,650	(3,235)
SIR Direct Resource Costs	12,419	16,925	4,506
	134,018	**135,127**	**1,109**

7. The Company continues to evaluate the 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 information becomes known, Enbridge may be required to re-prioritize originally anticipated program work.

8. The 2015 $1.1M underspend variance represents a 0.8% variance versus the approved budget of $135.1M.

9. Mains: Capital dollars were re-allocated from the originally budgeted spend across the mains portfolio through risk-based assessments and portfolio prioritization. Incremental capital was spent on mains replacement and assessment of high risk assets (eg: Ottawa - Innes Road replacement).

10. Stations: Efforts were focused on high risk initiatives such as regulators located inside customers' buildings, risk prioritization of district & header stations, records, station capacity, compliance items such as: fire protection, access, communications, gas pre-heat system mitigation. Expected station capacity issues associated with both Cookstown and Barrie Gates were not realized because of lower than forecast customer growth and have been deferred, further contributing to the variance.

11. Meters/Records/Envision: The overall variance ($3.2M) resulted from higher than budgeted spending on meter compliance units and Envision, offset by lower than budgeted spending on records initiatives.

12. SIR Direct Resource Costs: Departmental labor costs are primarily capitalized salaries and employee expenses. The Company committed in its Custom IR application to find productivity in this area. The favorable variance results from reductions in Enbridge's workforce and targeted hiring practices which have led to delays in filling some vacancies.

13. It is expected that the 2016 System Integrity and Reliability program costs will be at or higher than the 2016 OEB approved levels.

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 about 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 March 30, 2016 Stakeholder Day. (Please see page 69 of the Stakeholder Day materials found at Exhibit D, Tab 3, Schedule 1)

3. Later within its fiscal year 2016, the Company will be engaging its stakeholders in preparation of commencing a consultative to review and provide feedback on the required and planned study that Enbridge will be undertaking to benchmark the Company's required capital and operating costs. A request for Proposal (RFP) for an external expert is planned to be issued by the Company before the end of 2016.

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: L.Lawler
H.Sayyan

ASSET MANAGEMENT

Background

1. In its Decision with Reasons related to EB-2012-0459, the Board acknowledged Enbridge's Asset Management (AM) development but noted some shortcomings. The Board was clear in its view that robust asset management planning at Enbridge should:

   - Include all the Company's assets; and
   - Have a direct linkage to the budget

   Furthermore, the Board noted that an asset plan should:

   - Be the vehicle to perform rationalization, prioritization, and optimization, and
   - Be based upon a comprehensive process of condition assessment, risk evaluation, and prioritization

2. The Company provided a progress update early in 2015: EB-2015-0122, Exhibit D, Tab 1, Schedule 6.

2015/2016 Progress Update

3. At the March 30, 2016 Stakeholder Day, the Company reported on the status of the AM initiatives. This is set out at pages 70 to 88 of Exhibit D, Tab 3, Schedule 1.

Witness: T. MacLean

4. As explained, the Company has made significant progress in the design and implementation of its AM system over the past year. The Company's AM process will include all of the Company's assets. The AM system will be an important input for budgeting decisions, supporting the optimization of all asset related investments over a multi-year planning horizon.

5. The Company has procured multiple software solutions to enable an end to end linkage of the core AM system, from understanding the actual condition of assets through to optimized investment planning and production of multiyear asset plans and budgets. These software solutions are being implemented over the coming year.

6. The Company has an aspirational goal of ISO 55000 compliance. Enbridge has contracted a 3rd party (UMS) to assist with completing a comprehensive Asset Health Review (AHR) and developing a sustainable methodology for establishing condition and probability of failure. Later in 2016, Enbridge plans to engage an auditor to complete an assurance review on the AHR noted above. Enbridge also plans to engage an ISO 55000 certified assessor to benchmark the Company's overall approach to AM, provide an initial gap analysis, and provide follow-up review(s) as appropriate.

Witness: T. MacLean

PRODUCTIVITY INITIATIVES SUMMARY

Introduction

1. The purpose of this evidence is to present the 2015 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 2nd 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, reported through incremental initiatives;

Witnesses: L. Lawler
M. Yan

(vi) In total, productivity savings during the 2nd year of the Custom IR term are as anticipated and the Company will work to continue to find ongoing opportunities;

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

4. This evidence is structured as follows:

(i) Embedded O&M and Capital Reductions

(ii) Incremental Productivity Initiatives

(iii) Excluded Variable Capital Costs

(iv) Summary and Sustainability of Savings

(v) Performance Measures

Background

5. The Company issued its 2014 Productivity Report in EB-2015-0122 where it laid out the background to the productivity targets to be met during the Custom IR term, and the ways that this would be approached. Enbridge has maintained a similar approach in this 2015 Productivity Report. For details on the productivity background and methodology please refer to EB-2015-0122 Exhibit D, Tab 2, Schedule 1, paragraphs 4 through 17.

6. Tables 1 and 2 show the Core Capital and Other O&M amounts approved over the Custom IR term with emphasis on the 2015 budget. Productivity commitments in the form of embedded savings and excluded variable capital costs are similarly shown. The OEB Adjustment in Table 2 kept O&M increases to a level of 1% per year, resulting in a cumulative reduction of $42.2 million over the IR term making

productivity improvements critical to the Company operating within its approved amounts.

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 Reduction	(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)	(264.5)
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 Reduction	(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

7. This evidence will describe the work items, initiatives, and programs sustained from 2014, as well as those newly implemented by the Company in 2015 to deliver on the embedded reductions of $58.8 million ($28.7 million in capital and $30.1 million in O&M). It will also describe the status of the excluded variable capital costs ($63 million) which were uncertain cost requirements excluded from the proposed capital amount.

Witnesses: L. Lawler
M. Yan

Embedded O&M and Capital Reductions (Productivity)

8. Embedded productivity reductions 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.

9. Table 3 lists the embedded productivity reductions in 2015 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 commitments embedded in the Company's forecasts (EB-2012-0459, Exhibit J1.6).

Table 3:

2015 Embedded O&M Reductions	Embedded Commitment ($M)
Merit increase	(2.0)
Employee Benefits	(2.2)
Incremental cost to service new customers	(1.6)
Incremental safety and integrity work	(9.1)
External contractor rate increases	(1.4)
Increased volume of locates-compliance with Bill 8	(3.2)
FTEs	(5.7)
Bad Debt expenses	(5.0)
Total O&M Productivity Guarantee	(30.1)
2015 Embedded Capital Reductions	**Embedded Commitment ($M)**
Customer Attachments	(25.5)
Departmental Labour	(3.2)
Total Capital Productivity Guarantee	(28.7)

10. 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.

11. 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 2015 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 $0.4 million which was $1.6 million short of the embedded reduction for 2015.

12. 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 $0.4 million. The Company remains committed to managing to the lower rate of increase to mitigate cost increases.

13. Incremental costs to service new customers represent the costs to carry out Fuel Safety Branch Inspections ("FSBIs") which are required when gas is introduced to a premise for the first time. These costs were higher than budgeted as a result of a one-time unbudgeted Survey cost for premises within the High Pressure / Extra High Pressure class. Costs were $1.3 million in excess of the committed level.

14. Distribution Operations and Pipeline Integrity & Engineering continued to create operations efficiencies throughout 2015. In the Integrity group, O&M efficiencies of $0.9 million were achieved by applying new innovative solutions for cleaning tools for pipeline inspection, vendor sourcing and storage well inspection re-evaluation.

Distribution Operations continues to achieve productivity savings from its prior reorganization along functional lines of accountability from the traditional Regional structure (geographically based organization). The functional structure continues to drive greater streamlining, consistency and efficiencies. For example, decentralized workload planning created greater integration between work planning and work execution. Improvement to labour optimization through field on-call coverage consolidation resulted in efficiencies in standby. Training provided to field technicians allowed them to complete work historically assigned to different groups or external contractors. Externally, Operations worked closely with local municipalities to plan maintenance and replacement activities with cities' road paving programs to reduce overall operational costs. In 2015, the Company identified $1.1 million embedded savings related to productivity improvements in Operations. Safety and Integrity embedded savings totalled $2.0 million.

15. By centralizing the oversight of contract management functions, the Company has generated external contractor savings estimated at $0.4 million in 2015.

16. 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 7.4% over 2014 volumes, productivity commitments were embedded within the 2015 O&M budget by increasing locate budgets by only 3.4% in 2015. The associated embedded productivity commitment was $3.2 million.

17. 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 12% 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 and through reduced Ontario One Call Notification Fees. These initiatives have resulted in savings of $2.1 million in 2015.

18. A key industry benchmark measuring Damage Prevention program effectiveness is the Damages per 1000 Locates metric. Damage Prevention demonstrated continuous improvement by reducing the measure from 2.49 in 2014 to 2.43 in 2015 representing a 2.4% 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.

19. By year-end, FTEs were lower than the 2015 budgeted amount of 2,364 by 174 positions. Departmental Labour Costs (DLC) that were capitalized relate to back-office type functions such as planning, drafting, pipeline inspections, field operations and records management within the Operations and Engineering departments and as such are not impacted by delays in Capital projects. FTE savings are the salary & wage reductions expected to be sustained throughout the Custom IR term and are exclusive of severance costs. The combination of these efforts resulted in O&M FTE savings of $8.2 million and Capitalized Departmental Labour savings of $11.6 million.

20. Bad debt expense was held flat at $9.5 million within the 2015 O&M budget, although indications were that this expense would be around $14.5 million on the basis of commodity forecasts and the overall level of consumer indebtedness. Actual 2015 bad debt expenses were $10.0 million resulting in savings of $4.5 million.

21. Embedded productivity commitments in the area of Customer Attachment capital were partially met in 2015. While actual spending in this area exceeds the budgeted amount by $11.7 million, savings of $13.8 million were achieved relative to the embedded target primarily through the establishment of long-term construction contracts to achieve cost certainty through the Custom IR term. Customer Attachment capital was overspent primarily due to the customer segment mix and geographical distribution of customers specifically in commercial and industrial replacements. Third party fees, material costs and pipeline contractor labour costs per customer continue to increase. Additionally, winter construction activity has been on the rise, causing construction costs to be higher due to winter premiums charged by contractors.

22. To help mitigate these pressures, the Company continues to establish long-term construction contracts in order to stabilize/reduce costs. To manage costs, the Company continues to look for ways to manage timing of construction projects to avoid future winter premiums and has established an Internal working group to manage third party fees.

23. Table 4 details the estimated savings for each embedded productivity area in O&M and capital, respectively.

Table 4:

2015 Embedded O&M and Actual and Capital Reductions		Embedded Commitment ($M)	Actual ($M)
1.	O&M: Merit increase	(2.0)	(0.4)
2.	O&M: Employee Benefits	(2.2)	(0.4)
3.	O&M: Incremental cost to service new customers	(1.6)	1.3
4.	O&M: Incremental safety and integrity work	(9.1)	(2.0)
5.	O&M: External contractor rate increases	(1.4)	(0.4)
6.	O&M: Increased volume of locates-compliance with Bill 8	(3.2)	(2.1)
7.	O&M: FTEs	(5.7)	(8.2)
8.	O&M: Bad Debt expenses	(5.0)	(4.5)
9.	Total Estimated O&M Reductions	(30.1)	(16.7)
10.	Capital: Customer Attachments	(25.5)	(13.8)
11.	Capital: Departmental Labour	(3.2)	(11.6)
12.	Total Estimated Capital Reductions	(28.7)	(25.4)
13.	Total Estimated Embedded O&M & Capital Reductions	(58.8)	(42.0)

24. Of the $30.1 million guaranteed O&M savings, cost mitigation efforts achieved $16.7 million most effectively through FTE management. Of the $28.7 million guaranteed capital savings, cost mitigation efforts achieved $25.4 million. Relative to the total O&M and capital guaranteed savings, the Company achieved $42 million of the $58.8 million target.

25. In the first year of the Custom IR term, capital productivity was calculated as the amount of capital savings achieved relative to the overall Core Capital budget that was approved. As noted in EB-2015-0122 Exhibit D, Tab 2, Schedule 1 paragraph 54, the Company anticipated that in future years it might refine its approach to measuring productivity savings, to take advantage of learnings in the first year of the Custom IR term. As an ongoing improvement to the productivity reporting, in the 2nd year of the Custom IR term, Enbridge has taken a more detailed approach, and instead of comparing the overall spend to the approved budget, the Company

has looked at particular initiatives in order to measure incremental capital savings (in addition to those reported in Table 4) resulting from productivity actions. This approach allows the Company to quantify capital productivity results by eliminating savings that might be due to one-off circumstances, changes in scope and delay or cancellation of budgeted capital projects. The Company continues to manage the fixed capital budget under increasing cost pressures and deliver to its operational requirements and commitments within the approved amounts. The results for capital incremental initiatives (in addition to O&M results) are reported in the following section.

Incremental Productivity Initiatives

26. Productivity actions or initiatives that are in addition to the items set out in Table 4 were pursued in all areas of the Company, across all levels of employees.

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

28. Over one hundred and fifty (150) productivity initiatives were identified throughout the organization. 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

29. In addition to the $8.2 million in O&M FTE reductions and $11.6 million in capital DLC savings identified in the earlier part of this evidence (and in Table 4), 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. For example, EHS Training courses were developed by existing internal resources instead of outside consultants. In addition, many of the training courses were re-designed as online courses, therefore eliminating travel expenses and allowing schedule flexibility to employees. The savings from these types of initiatives were estimated at $1.6 million in O&M and $0.6 million in capital.

30. Process Optimization initiatives relate to changes in the way work is organized to achieve efficiencies. These included system changes, more efficient work flows, streamlined tools, and the elimination of redundant reports. The savings from these types of initiatives were estimated at $5.7 million in O&M and $2.0 million in capital. For example, the e-bill initiative provides cumulative sustainable savings growing from $0.4 million in 2014 to $1.6 million in 2015. The number of e-bill adoptions continues to grow through active conversion strategies as well as an improved web interface which has facilitated the sign-up process generating savings throughout the full Custom IR term by eliminating increasing postage and print costs. In the area of departmental training and development, budgets were centralized in the Human Resources department. The centralization allows HR to work with leaders to understand the development needs across the Company and maximize learning opportunities within the available centralized budget. The Company was able to maximize internal and external course offerings, vendor pricing and other approaches resulting in savings of $0.8 million.

31. 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. For example, the IT department leveraged existing hardware to build a parallel testing environment, firstly for the SAP upgrade project and then secondly for the WAMS/CIS integration. This eliminated the need for purchasing additional hardware for each project. This group of initiatives achieved an estimated savings of $2.1 million in O&M and $3.2 million in capital.

32. 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, changed the manner in which services were contracted or delivered, or changed the type of material approved for use. For example, in 2014 a change was made to the Company's Carbon Monoxide ("CO") Alarm Response Policy to respond to CO calls only when assistance is requested by the first responder who attends to the call. 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. As a result of full year effectiveness in 2015, savings grew from $0.1 million to $0.2 million. Savings in this category of initiatives amounted to $0.8 million in O&M and $0.9 million in capital.

33. Incremental O&M savings from sustainable productivity actions in 2015 are estimated at $10.2 million. Some of these savings ($4.1 million) are from new initiatives. The balance of these savings is from the sustainment of 2014 productivity initiatives. As shown in Table 5, in 2014 the Company reported $3.5 million in savings from incremental O&M initiatives; ninety-seven percent of those savings were sustained, and the total savings from those initiatives grew to $6 million in 2015. As 2014 was the initial year of implementation with partially effective savings, 2015 results have demonstrated productivity sustainment and growth from the first year of the Custom IR term.

Table 5:

2015 Incremental O&M Productivity Initiatives				
Amounts reported in millions	2014 Initiative Results	2014 Sustained to 2015	New 2015 Initiative Results	Total 2015
Labour Optimization	(1.1)	(1.4)	(0.2)	(1.6)
Process Optimization	(0.8)	(2.3)	(3.4)	(5.7)
Materials/Space/Equipment Rationalization	(0.9)	(1.6)	(0.5)	(2.1)
Policy Change and Improvements	(0.7)	(0.8)	(0.0)	(0.8)
Total Reductions from Incremental O&M Initiatives	(3.5)	(6.1)	(4.1)	(10.2)

34. Incremental capital savings from sustainable productivity actions in 2015 are estimated at $6.7 million. As seen in Table 6, some of these savings ($2.6 million) are from new initiatives. The balance of these savings ($4.1 million) is from the sustainment of specific 2014 productivity initiatives that resulted in capital savings. Due to the project nature of some of the capital expenditures, not all initiatives identified each year are expected to be sustained in the remaining Custom IR term.

Table 6:

2015 Incremental Capital Productivity Initiatives				
Amounts reported in millions	2014 Initiative Results	2014 Sustained to 2015	New 2015 Initiative Results	Total 2015
Labour Optimization	(0.6)	(0.6)	0.0	(0.6)
Process Optimization	(0.8)	(1.0)	(1.0)	(2.0)
Materials/Space/Equipment Rationalization	(1.1)	(2.3)	(0.9)	(3.2)
Policy Change and Improvements	(0.2)	(0.2)	(0.7)	(0.9)
Total Reductions from Incremental Capital Initiatives	(2.6)	(4.1)	(2.6)	(6.7)

Variable Costs (Capital)

35. 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 developed. The excluded capital costs are pre-emptive savings within the total capital budget approved.

36. Similar to 2014, most of the variable capital costs identified for 2015 in the Custom IR filing have been determined to not have materialized.[1] Because of the uncertain nature of these variable cost elements, a number of projects have had subsequent changes in scope and/or timing that make it challenging to determine how these work items have ultimately been captured in the budget or in actual spend. The variable costs that did arise were mitigated or absorbed within the overall capital spending for 2015.

[1] See undertaking EB-2012-0459, Exhibit J1.6 for the detailed list of identified variable costs that were excluded from the final Capital budget.

Summary and Sustainability of Savings:

37. Through pooled efforts at all levels of the organization, the Company achieved its embedded reductions target of $58.8 million in 2015 through the combination of savings in embedded areas of productivity and incremental productivity initiatives. Table 7 provides a breakdown of the 2015 reductions achieved within the areas identified for productivity enhancement.

Table 7:

	2015					
	O&M ($M)		Capital ($M)		Total ($M)	
	Commitment	Actual	Commitment	Actual	Commitment	Actual
Embedded	(30.1)	(16.7)	(28.7)	(25.4)	(58.8)	(42.0)
Incremental		(10.2)		(6.7)		(16.9)
2015 Total Savings	(30.1)	(26.9)	(28.7)	(32.0)	(58.8)	(58.9)

38. The Embedded Reductions and Incremental Initiatives are expected to continue throughout the Custom IR term. Through consistent messaging and continued focus within the organization, the Company has seen heightened self-reporting of productivity efforts as employees and management drive to measurable results.

39. To ensure continued success, the Company will need to pursue additional improvements 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 Custom 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)

40. Table 8 and Table 9 compare 2015 operational metrics and customer service quality indicators (Exhibit D, Tab 5, Schedule 1) against 2013 and 2014 results to assess Enbridge's performance in light of the cost reductions achieved. As seen in the trending columns, productivity efforts have not compromised Enbridge's service levels. Time to Reschedule a Missed Appointment, though below target has a stable trend. Enbridge's overall performance measures show that it continues to offer safe and reliable service while improving its value offering to customers.

Table 8:

Operational Performance	2013	2014	2015	Trending
1. Employees Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	1.06	↑
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	2.43	↑
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.06	0.06	↔
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	905	↔
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	4.84	↑

Table 9:

Customer Relationship Performance	OEB Target	2013	2014	2015	Trending
1. Overall Customer Satisfaction Index	NA	78%	77%	79%	↑
2. Call Answering Service Level (SQR)	75%	75.9%	79%	79.7%	↑
3. Percentage of Emergency Calls Responded to within One Hour (SQR)	90%	96.1%	96.9%	96.7%	↔
4. Appointments Met within the Designated Time Period (SQR)	85%	94.2%	95.1%	95.2%	↑
5. Time to Reschedule a Missed Appointments (SQR)	100%	95.0%	95.5%	94.8%	↔
6. Number of Days to Reconnect a Customer (SQR)	85%	92.6%	94.0%	94.6%	↑
7. Number of Calls Abandon Rate (SQR)	10%	2.8%	1.9%	2.3%	↔
8. Meter Reading Performance (SQR)	0.5%	0.50%	0.69%	0.51%	↔
9. Number of Days to provide a Written Response (SQR)	80%	94.5%	93.3%	100.0%	↑

↑ – Improving
↔ – Maintained
↓ – Decreasing

Witnesses: L. Lawler
M. Yan

2016 Custom IR Stakeholder Day

Mar 30th, 2016

Moderated by:
Andrew Mandyam
Kevin Culbert

Agenda

Presenter	Topic	Time (incl questions)
Andrew Mandyam and Kevin Culbert	Company overview	9:00 - 9:20
Ryan Small	Year End Financials	9:20 - 9:35
Scott Dodd	GTA	9:35 - 10:00
Will Akkermans and Biju Misra	WAMS & IT	10:00 - 10:20
Hilary Thompson and Ian Taylor	Reinforcements and Relocations	10:20 - 10:30
Break (15 min)		
Fiona Oliver-Glasford	Cap & Trade	10:45 - 11:05
Lisa Lawler and Melinda Yan	Productivity and Benchmarking	11:05 - 11:30
Trevor MacLean	Asset Management	11:30 - 12:15
Andrew Mandyam and Kevin Culbert	Closing Remarks	12:15 - 12:30

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2014 Stakeholder Day Survey Results

- Survey sent to 11 OEB participants and 11 Intervenors
- Response rate: 55% (mostly intervenors)
- Highlights:
  - 75% of the respondents mentioned that the survey was at least somewhat better than expected
  - 83% of the respondents found the information useful
  - 100% of the respondents thought the information was organized
  - 75% of the respondents indicated that the length of the day was “about right”
  - 84% of the respondents mentioned the stakeholder day was well structured
  - Most of the respondents were at least “somewhat satisfied” with the event
- Comments from the survey regarding topics for next stakeholder day:
  - Discussion of drivers of earnings
  - Productivity measures and results

Company Overview

Andrew Mandyam
Kevin Culbert

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Last year and going forward

- Coldest Toronto February ever in recorded history
- 1st full year under Custom IR (post July 2014 decision)
- Safety
  - Over 800 days without a Lost-Time Incident
  - Corporate Safety Award for Employee Safety and Public Safety Leadership Award
- Company maintaining FTEs
- Work underway on major company initiatives
  - WAMS
  - Asset Management
  - GTA

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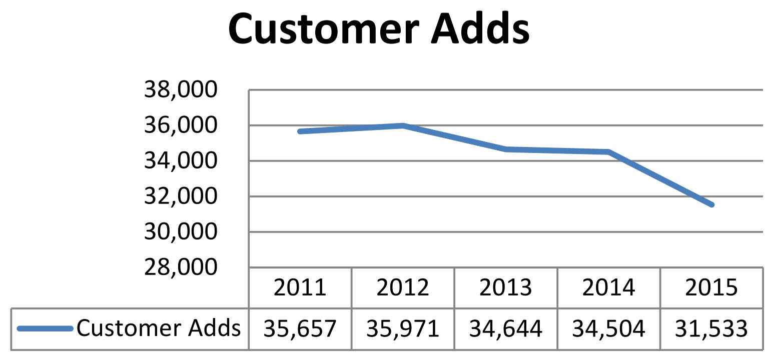
2015 What we did

- 31,533 Customers Attached



- 2,083,513 number of active customers at year end 2014 (EGD)
- 2,112,445 number of active customers at year end 2015 (EGD)

- Over 300 Km of Main related work in 2014 (installation, replacement, retired)
- Over 400 Km of Main related work in 2015 (installation, replacement, retired)
- Volumes throughput 2012-2015:

(Volumes in $10^6 m^3$)	2013 Actual Normalized	2013 Actual	2014 Actual Normalized	2014 Actual	2015 Actual Normalized	2015 Actual
Total Volumes, Gas Sales and Transportation	11 491.2	11 558.0	11 297.8	12 657.6	11,299.3	11,931.8

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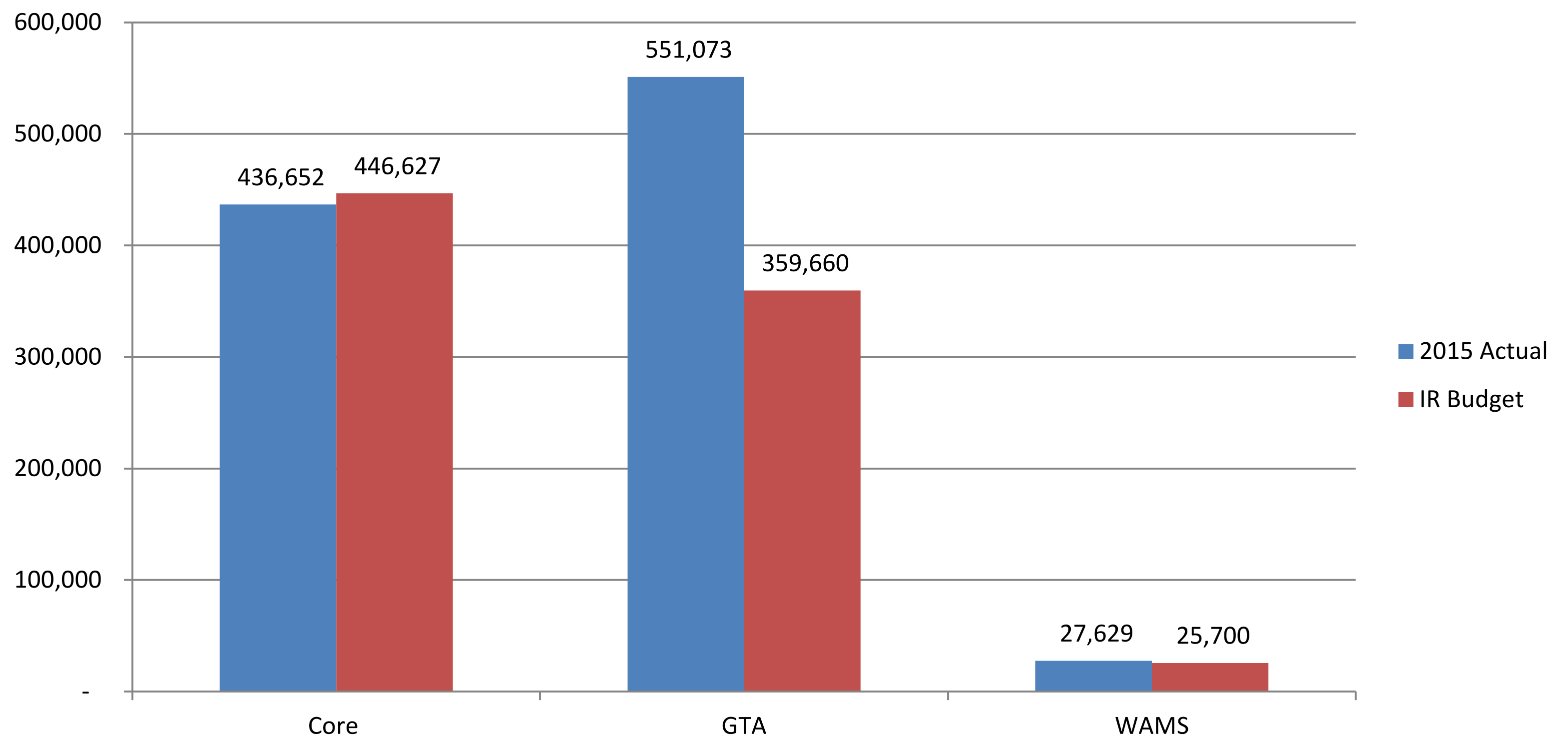
2015 What we did: Capital Management



- Majority of Total CAPEX higher spend ($183MM) is due to GTA project

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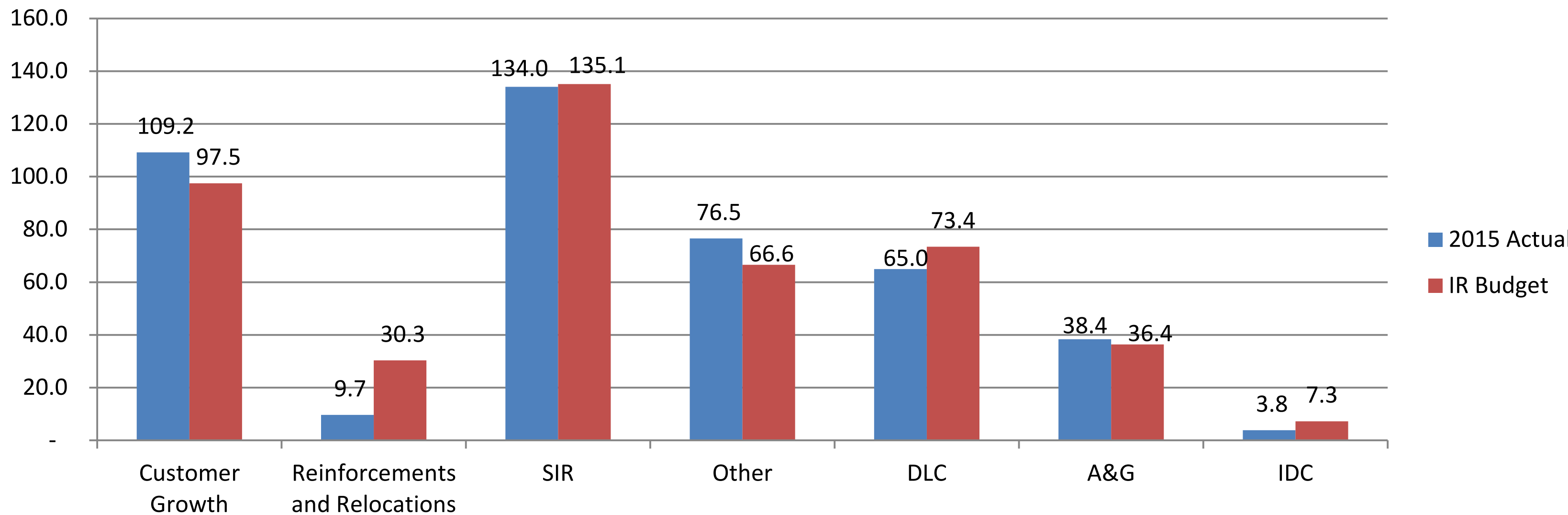
2015 What we did: Capital Management



Total Core CAPEX – Major Drivers

- Customer Growth ($12M over): Mix of work
- Reinforcements and Relocations ($20M under): Network analysis outcomes and higher cost recoveries than budgeted
- Facilities and Fleet ($9M over): Building improvements; Vehicles and Heavy Equipment replacement
- Storage ($10M over): Compressor Plant Office Building construction in 2015 (budgeted in 2014)
- IT ($6M under): ITSS centralization & Information and Productivity Services
- DLC and IDC $12M under: Reduced work force, work mix and some project delays

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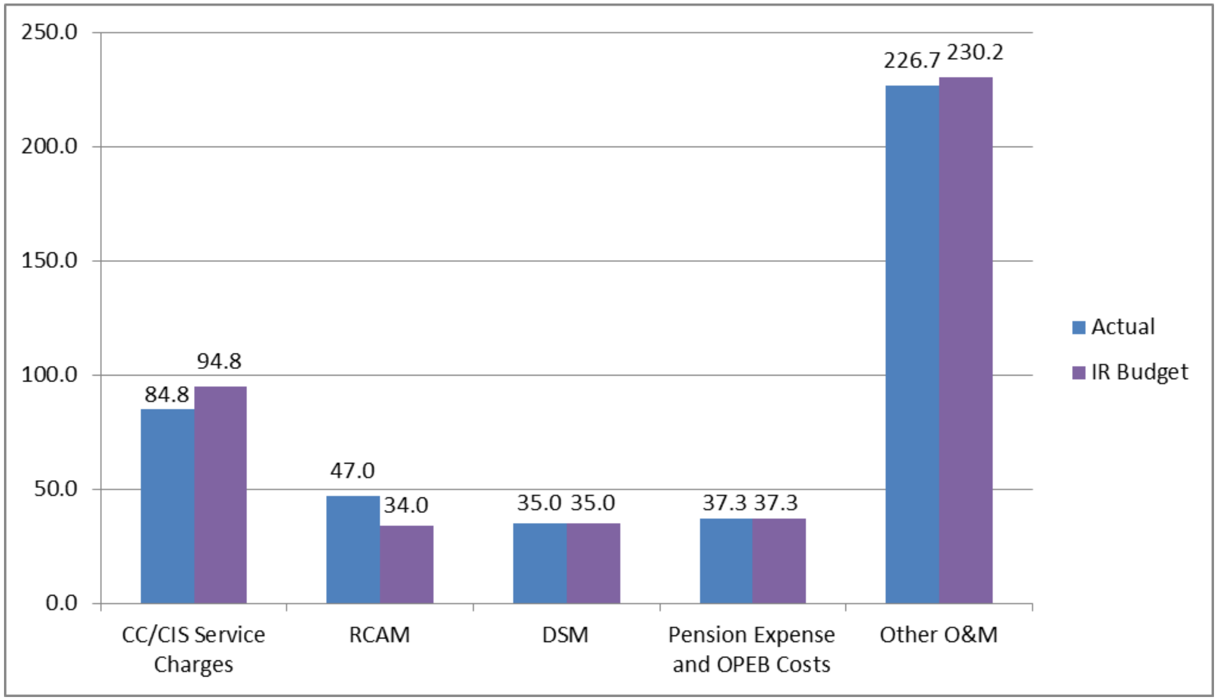
2015 Utility O&M

Line No.	Cost Categories ($ Millions)	2015 Actual	2015 IR Budget	Variance
1.	CC/CIS Service Charges	84.8	94.8	10.0
2.	RCAM	47.0	34.0	(13.0)
3.	DSM	35.0	35.0	0.0
4.	Pension Expense and OPEB Costs	37.3	37.3	0.0
5.	Other O&M	226.7	230.2	3.5
6.	**Total Net Utility O&M Expense**	**430.7**	**431.3**	**0.6**

2015 Utility O&M



Major Drivers:

1. Customer Care $10M lower due to CIS support costs, collections process, postage from higher number of customers on e-bill, and system improvements reducing manual work
2. RCAM $13M higher due to centralization of IT and HR services
3. Other O&M $3.6M lower due to IT and HR shared services, stakeholder/customer communication costs, sponsorships/donations, and A&G capitalized, partially offset by other business costs

2016 Regulatory Activity

– Cap and Trade Regulatory Framework Consultation	EB-2015-0363
– Updating Filing Requirements for Nat. Gas Distr.	EB-2016-0033
– Generic Nat. Gas Expansion to unserved Communities	EB-2016-0004
– Gas Supply Planning Consultation (report in Q2/Q3)	EB-2015-0238
– Regulatory Treatment Pension / OPEB costs	EB-2015-0040
– OEB initiated Cost of Capital Review (timing unknown)	
– EGD 2016 Final Rate Order with DSM Decision	(late April / with July QRAM)
– EGD 2015 ESM & Def / Var accounts application	April 2016
– EGD 2017 Rate Proceeding	Sept. 2016
– QRAM applications for July & October 2016	June & September 2016
– EGD Storage & Transp. Access Rule Application	EB-2016-0028

Year-end Financials

Ryan Small

2015 Utility Return on Equity – Actual vs. Approved

– 2015 Gross Revenue Sufficiency = $12.9M

– 2015 ESM = $6.45M

– 2015 Actual Normalized ROE Before ESM = 9.82%

– 2015 Actual Normalized ROE After ESM = 9.56%

– 2015 Board Approved ROE = 9.30%

2015 Allowed Revenue & Sufficiency – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2014-0276 Approved (Incl. CIS)	Variance
1.	Rate base	5,079.8	4,956.5	123.3
2.	Required rate of return	6.465%	6.523%	(0.058)%
3.	Cost of capital	328.4	323.4	5.0
	Cost of service			
4.	O&M (incl. CC/CIS rate smoothing adj.)	430.7	431.3	(0.6)
5.	Depreciation and amortization expense	259.7	261.7	(2.0)
6.	Fixed financing costs	3.4	1.9	1.5
7.	Municipal and other taxes	41.6	43.1	(1.5)
8.	Other revenues	(50.1)	(42.8)	(7.3)
9.	Income taxes on earnings	19.4	15.4	4.0
10.	Taxes on sufficiency	(3.4)	-	(3.4)
11.	Allowed revenue	1,029.7	1,034.0	(4.3)
12.	Revenue at existing rates, net of gas costs	1,042.6	1,034.0	8.6
13.	Gross revenue sufficiency	12.9	-	12.9

* 2015 earnings sharing payable to ratepayers = $6.45M

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2015 Utility Rate Base – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2014-0276 Approved (Incl. CIS)	Variance
1.	Net property, plant, & equip.	4,606.1	4,573.8	32.3
2.	Gas in storage	481.1	403.6	77.5
3.	Other working capital items	(7.4)	(20.9)	13.5
4.	Utility Rate Base	5,079.8	4,956.5	123.3

- PP&E – higher opening balance, offset by the impact of the GTA and WAMS projects which did not close into service as forecast.
- Gas in storage – higher than forecast utility volumetric balances.

2015 Utility Capital Structure – Actual vs. Approved

2015 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	2,985.7	58.78	5.15	3.030	153.9
2.	Short term debt	165.4	3.25	1.32	0.043	2.2
3.	Preference shares	100.0	1.97	2.24	0.044	2.2
4.	Common equity	1,828.7	36.00	9.30	3.348	170.1
5.		5,079.8	100.00		6.465	328.4

EB-2014-0276 2015 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,002.2	60.57	5.14	3.114	154.3
2.	Short term debt	70.0	1.41	1.45	0.020	1.0
3.	Preference shares	100.0	2.02	2.20	0.044	2.2
4.	Common equity	1,784.3	36.00	9.29	3.345	165.8
5.		4,956.5	100.00		6.523	323.4

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2015 Utility Income – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2014-0276 Approved (Incl. CIS)	Variance
1.	Distribution margin (dist. rev. - gas costs)	1,042.6	1,034.0	8.6
2.	Other revenues	50.1	42.8	7.3
3.		1,092.7	1,076.8	15.9
4.	O&M (incl. CC/CIS rate smoothing adj.)	430.7	431.3	(0.6)
5.	Depreciation and amortization expense	259.7	261.7	(2.0)
6.	Fixed financing costs	3.4	1.9	1.5
7.	Municipal and other taxes	41.6	43.1	(1.5)
8.	Total costs and expenses	735.4	738.0	(2.6)
9.	Utility income before income taxes	357.3	338.8	18.5
10.	Income tax expense	19.4	15.4	4.0
11.	Utility net income	337.9	323.4	14.5

- Margin – higher LV CD revenues & lower S&T fuel charges, partially offset by lower customer unlocks and unrealized rate 332 revenues.
- Other revenues – gain on the sale of BP gas & higher LPP revenues.
- O&M – lower CC & CIS, HR & IT costs, offset by higher RCAM and other business costs.
- Depreciation – impact of the GTA project and higher retirements.
- Fixed financing charges – impact of increased credit facility.
- Municipal taxes – impact of the GTA project and lower than forecast rates.

Utility Return on Equity – Actual vs. Approved

	2015	2014
- Gross Revenue Sufficiency	$12.9M	$25.3M
- ESM Amount	$6.45M	$12.65M
- Actual Normalized ROE Before ESM	9.82%	10.46%
- Actual Normalized ROE After ESM	9.56%	9.91%
- Board Approved ROE	9.30%	9.36%

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GTA

Scott Dodd

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

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GTA Project Map

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GTA Project Scope

Segment A

- Shared Regional Transmission / Distribution Pipeline
  - 26.49 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
  - 23.04 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 Gate Station
- Keele / CNR Station
- Jonesville Station (renamed Ashtonbee Station to be built in Q3 2016)
- Buttonville Station (to be built in 2017)

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Project Status

– Safety – Project TRIF 0.94

– Project scope is in service (except for Ashtonbee and Buttonville)

- Segment A in service on March 22, 2016
- Segment B in service on March 30, 2016

– Jonesville Station now relocated to Ashtonbee

- In April 2015, HONI advised EGD that it would not permit new station to be constructed under high voltage overhead wires due to a change in policy.
- This was contrary to previous communication with HONI showing preference for the Jonesville Site
- As a result of this change, Ashtonbee Station will now be constructed prior to 2016 heating season
- Request to vary was approved by the OEB on February 5, 2016., approving the change in location, working with City of Toronto on minor zoning variance on easements

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Project Status Cont'd

– Forecast cost $922 MM
  - Down from previous forecast of $932 MM communicated in November 2015.
  - KPMG engaged as an independent risk/prudency advisor
  - LTC cost forecast $687 MM

– Construction market conditions, construction complexity and permit delays/conditions were the primary reasons for the increase…..

Narrow corridor construction issues

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Complexity

[redacted]

Pig Launcher at Parkway

Bore pit at Leslie

Drivers of 2015 Actuals ($MM)

	2015	Project
2015 EB-2012-0459 Approved	359.7	686.5
2015 Actuals	551.0	
Variance to EB-2012-0459 Approved	191.1	

– Total Project forecast is $922 MM

Key Cost Overage Drivers

- Escalation of construction bid price relative to what was filed in EB-2012-0451
  - At the time of bidding in 2014, pipeline construction market was highly escalated with multiple major projects in North America
- Increased costs associated with greater construction complexity relative to the design basis and cost estimate filed in EB-2012-0451
  - Increased depths driven by permitting agencies, and proximity to major infrastructure (Foreign pipelines, sewers, watermains) required expensive shoring for safety reasons and extra workspaces in an already narrow corridor.
  - Major changes to construction methodology (Extra depth, re-routing) and monitoring of adjacent utilities driven by agency requests
  - Ground conditions caused problems with several trackbores and required the addition of two last minute direct pipe installations
- The agencies took longer for permitting which drove a five month schedule extension
  - Agencies lacked experience in permitting a large diameter gas pipeline, permits were delayed well beyond normal processing time based on previous EGD experience
  - Additional project management, construction support and oversight, mainline contractor costs and interest expenses due to extended schedule

Summary

– 2016 Considerations

- Final construction, commissioning and energization (Completed for both segments)
- Final clean up
- Environmental monitoring
- LTC filings

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WAMS

Will Akkermans
Biju Misra

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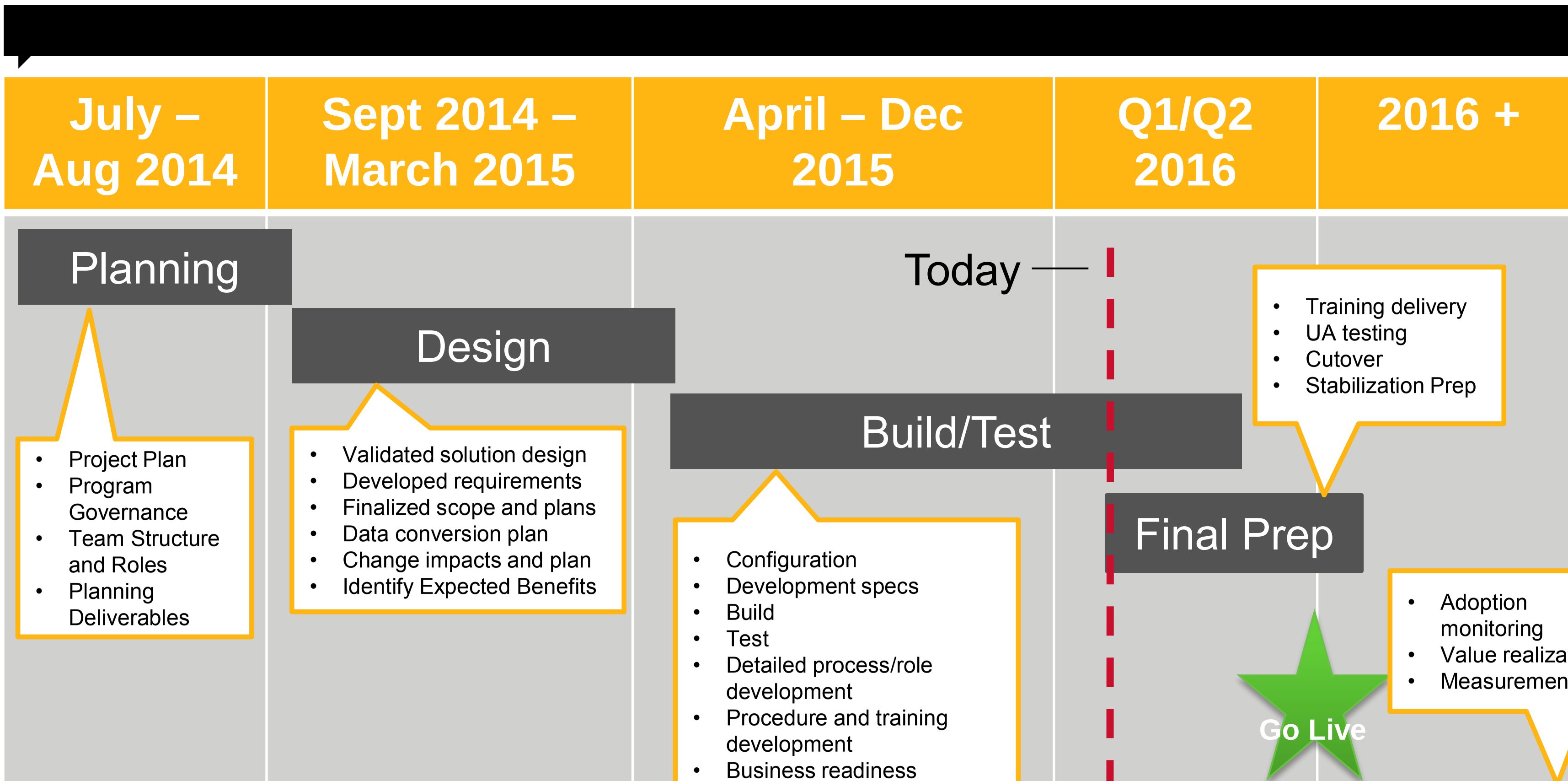
Background

- 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 1,800 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.

WAMS Implementation Approach



WAMS Annual Capex (Exhibit Ref: B2-8-2 WAMS)	IR Budget	Actual / Forecast	Variance
For the year 2014	36,300	19,606	16,694
For the year 2015	25,700	27,629	(1,929)
For the year 2016	8,100	30,817	(22,717)
Total	70,100	78,052	(7,952)

Successes

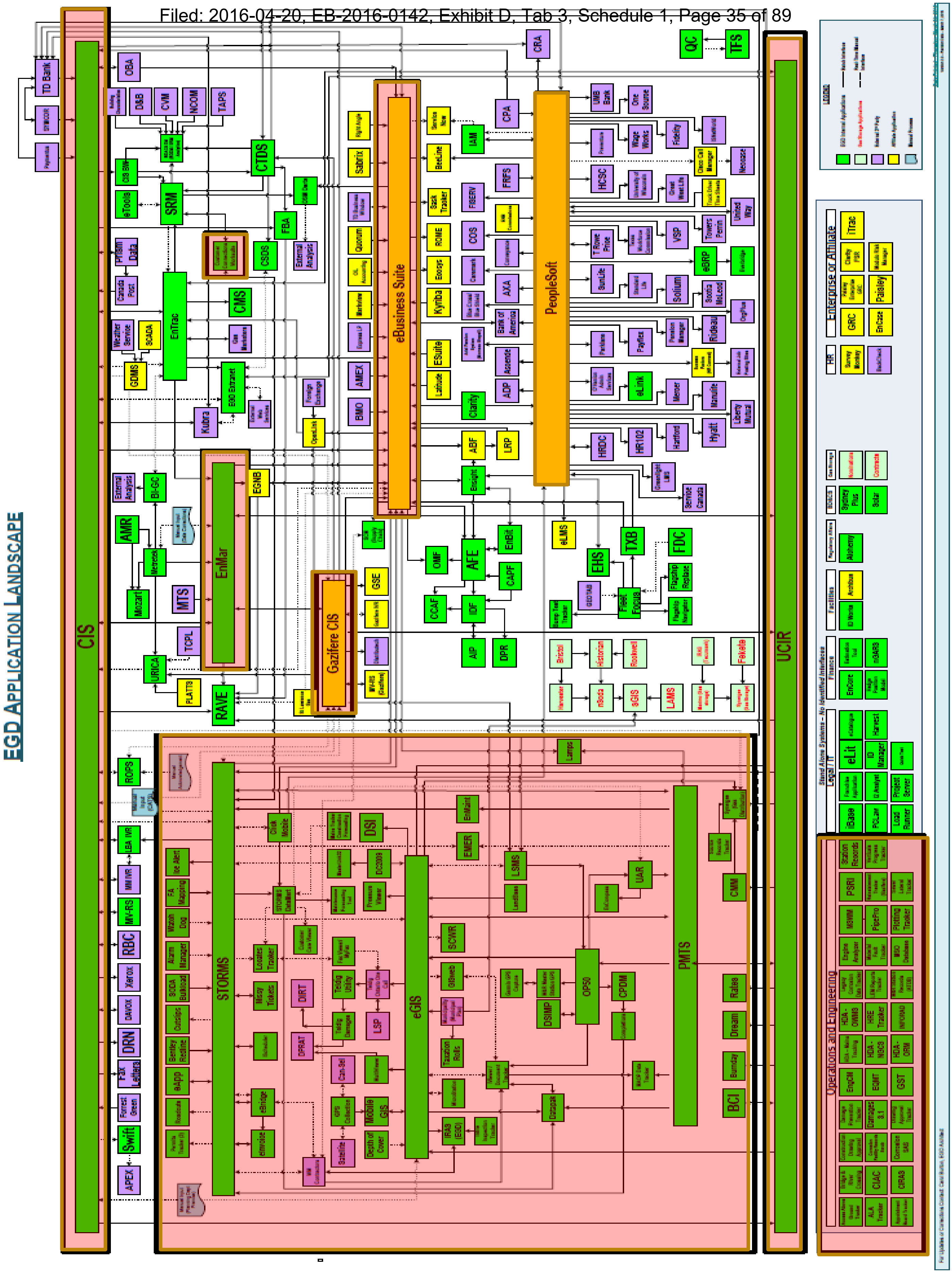
– Completion of Design & Build Phases
  - Maximo and Click technology is the “right fit” for Enbridge

– Iterative approach of Functional Unit testing
  - Over 1000 defects fixed

– Business readiness activities on track

– Early indications of formal System Integration test results are positive

– Maintaining appropriate balance between Quality, Schedule and Cost


EGD Application Landscape
CIS
UCIR
eBusiness Suite
PeopleSoft
STORMS
eGIS
PMTS
EnMar
Gazifere CIS
EnTrac
SRM
CTDS
RAVE
AFE
TXB
FDC
EHS
QC
TFS
CRA
CPA
Operations and Engineering
Enterprise or Affiliate
Stand Alone Systems – No Identified Interfaces
LEGEND

Technology and Business Complexity

Technology

– 20+ systems to interface; 60+ interfaces to build
– 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

Business

– Over 200 people across the company have been involved in requirement definition / design
– 32 key end-to-end business processes analyzed, streamlined, and documented
– Over 700 business requirements have been identified as critical for meeting operational commitments and compliance
– 220 training sessions planned

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Challenges

– Finalizing design was more complex then anticipated resulting in extending the project duration
  - 194 functional specifications
  - 271 technical specifications

– Breadth and scope of testing to ensure a quality solution is delivered
  - More than 15,000 test scripts developed
  - Extended test windows

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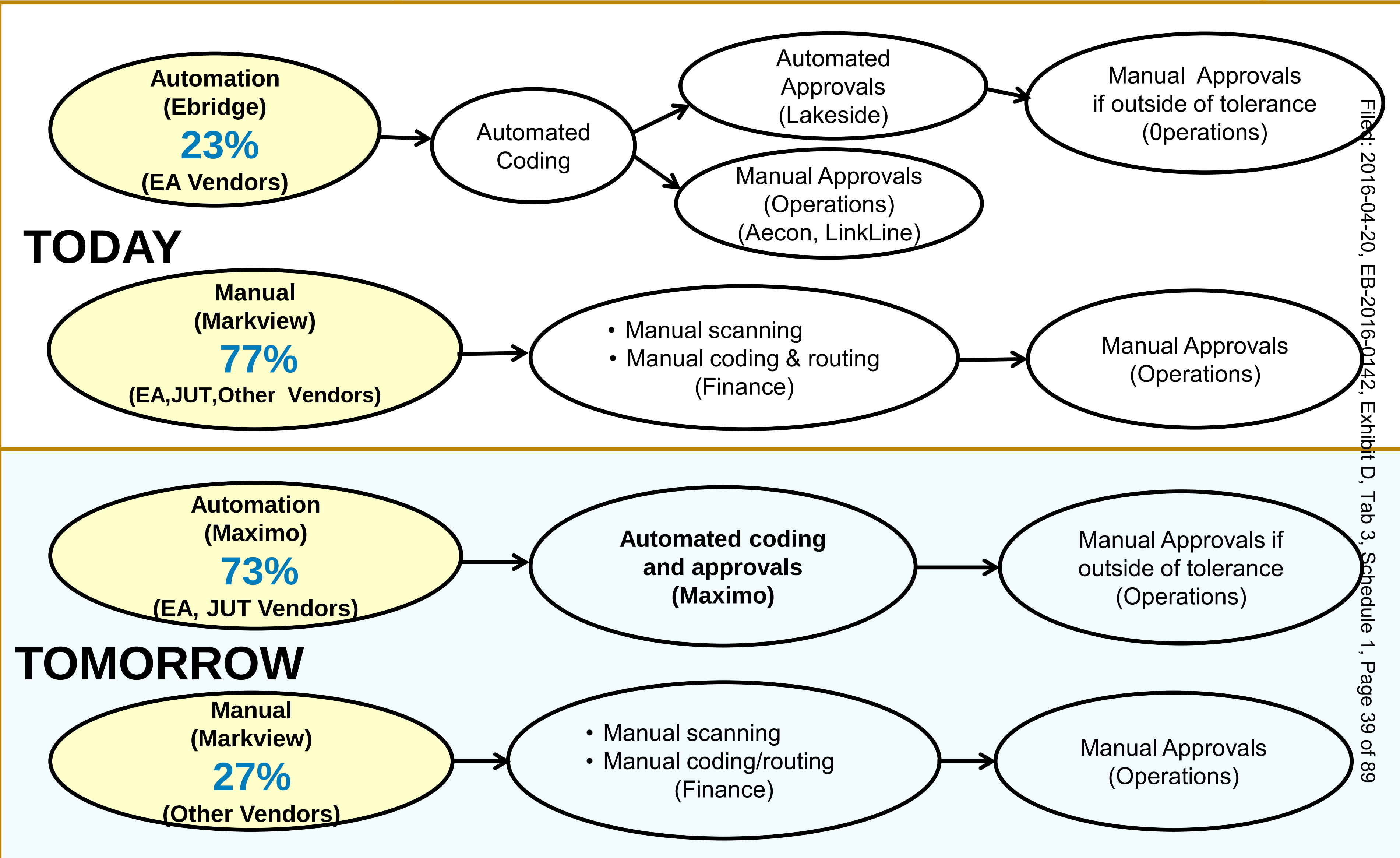
Expectations post GO-LIVE

- **Primary benefit is to replace obsolete technology to manage risk**
- **WAMS will deliver enterprise-wide benefits**
  - Safety, Productivity, Customer Satisfaction, Employee Satisfaction, and Finance
- **Examples of benefit areas through People, Process, Technology and Data**
  - Workflow management & monitoring
  - Financial management
  - Forecasting
  - Dependency management
  - Visibility to information
  - Planning / Scheduling / Dispatching of work
  - Invoicing

Post Go-live Improvement area: Contractor Invoicing



More streamlined approval process

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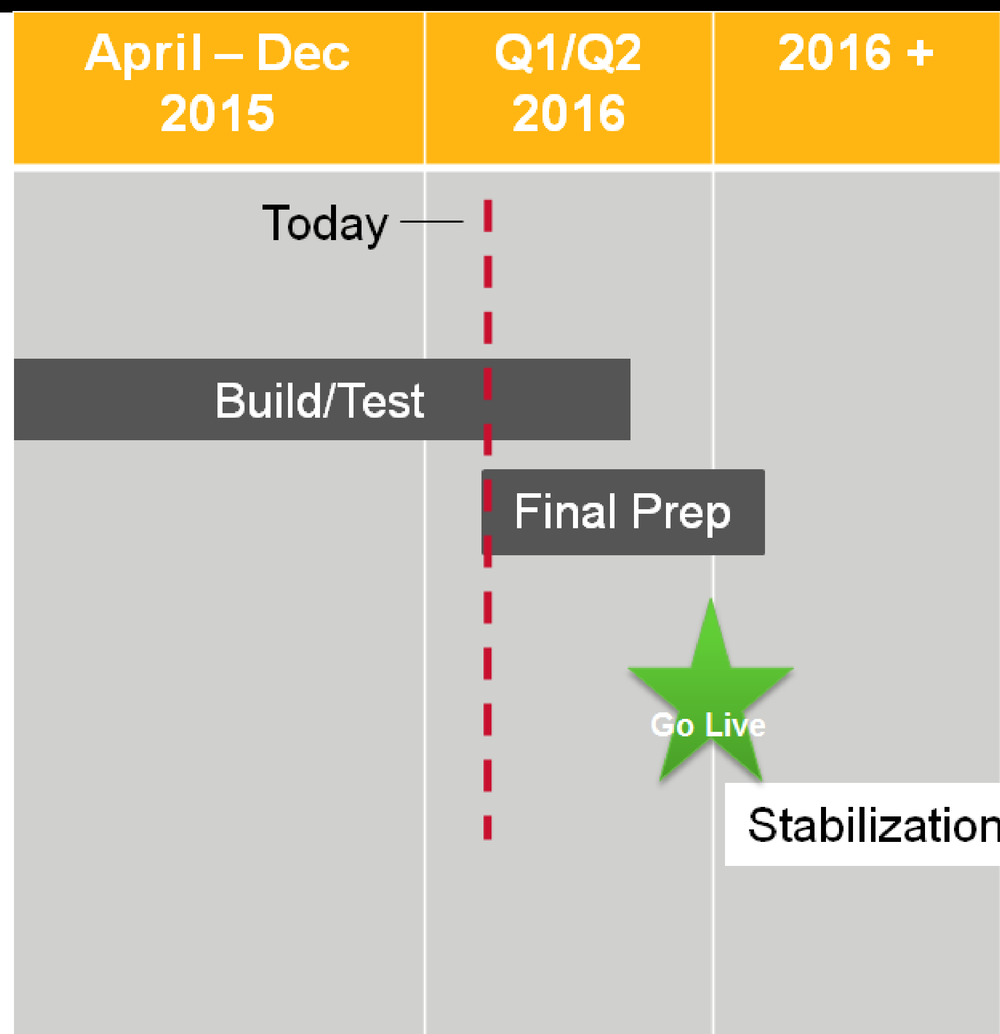
Summary


April – Dec 2015
Q1/Q2 2016
2016 +
Today
Build/Test
Final Prep
Go Live
Stabilization

IT

Biju Misra

2015 IT capital spend variance; spend under by $6M

Major drivers:

WAMS Program: Enbridge expects to have WAMS Go-Live in Q3, 2016. This initiative represents a significant transformational activity for the Company. The increased complexity in implementation of WAMS has involved significant company resources who have not been available for other IT projects and impacting IT's ability to plan and execute.

– **IT Infrastructure:**

- **Consolidation of IT Infrastructure within Enbridge Inc (IT Shared Services):** The capital spend for IT Infrastructure, which includes Network Services, Data Centre Operations and IT Risk Management, is now contained within IT Shared Services (as per ARC exemption filing for IT Shared Services with OEB) and services are provided to EGD and other business units on a standard, consistent and cost effective basis. This has resulted in a savings of approximately $3 million.

- **Information & Productivity Services (I&PS):** This is an IT shared service that implements and upgrades to email, back office tools like Microsoft office, Sharepoint, and other products. Reduction in capital spend of $2.5M due to other projects within I&PS taking a higher priority. The new timing of this spend is 2016 and will be managed as part of 2016 budget.

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Reinforcements and Relocations

Hilary Thompson
Ian Taylor

Reinforcements

– Reinforcements are primarily driven by customer growth and system reliability considerations to meet the anticipated peak hourly demand.

– Projects are identified through the completion of four major functions: load gathering, simulation, annual forecast, and long range system planning.

– As a result of these functions, the timing of reinforcements are evaluated on an annual basis to trigger projects when needed.

Reinforcements

Reinforcements	2015 Actuals	2015 IR Forecast	2016 IR Forecast
Total ('000)	$4,715	$16,958	$8,743

– 2015 variance:

- When submitted in 2014, the IR filing considered the execution of:
  - York Region reinforcement in 2015, however this project has been re-forecasted to 2018 due to the process discussed (winter monitoring, simulation, forecast) and latest available information. This moved $10M from the 2015 budget.
  - Alliston reinforcement was forecast primarily in relation to a specific customer. This project is timed around their load addition and is not expected to proceed in the near future. ($1M)
  - Smaller reinforcements forecast total $5.5M – actuals $4.7 – approximately $800K of projects deferred or cancelled

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Relocations

- At times, Enbridge is required to relocate its infrastructure to accommodate 3rd party construction; municipalities, MTO, public transit expansion projects, etc. These relocations are deemed mandatory based on various franchise and legal agreements, as well as legislative acts; Drainage, Public Service Works on Highways Act, etc.
- Relocations are directly dependent on external infrastructure spending and timelines.
- Cost apportionment for relocations are determined by the type of work, where the work is being performed and who is requesting the work.

Yonge & Eglinton Relocation for Metrolinx

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Relocations

Relocations	2015 Actuals	2015 IR Forecast	2016 IR Forecast
Total (‘000)	$4,954	$13,386	$12,603

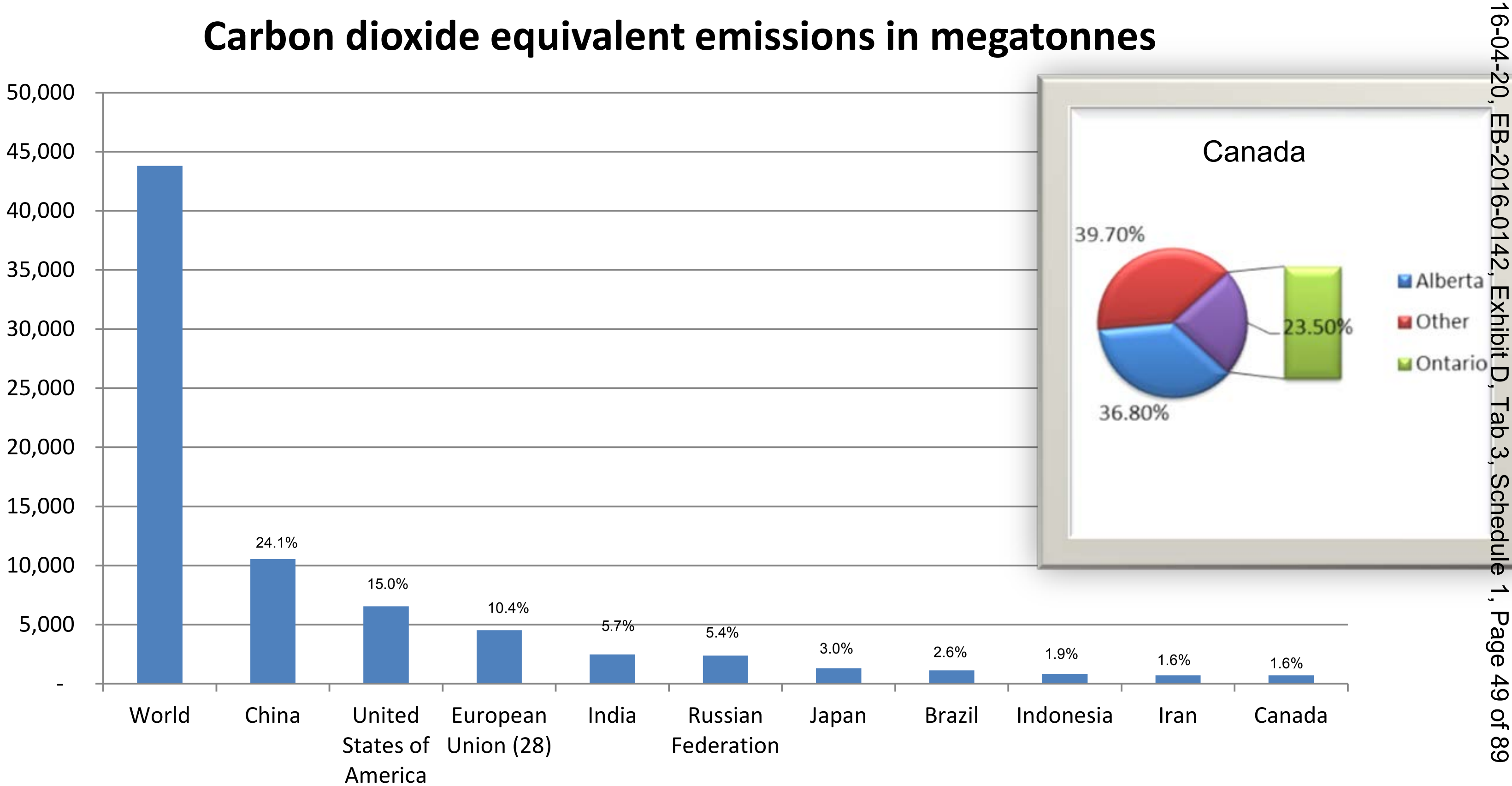
- Volume of overall work was similar to 2014, there was a high proportion of credits in 2015 - $24M (compared to $21M in 2014 and $17M in 2013).
- Regional transit work and other large scale infrastructure work continue to be the biggest impact.
  - York Region Rapid Transit (YRRT)
  - Metrolinx

EGD is working closely with external agencies on their large infrastructure work to establish long range timelines for a 1-3 year outlook.

Carbon Strategy & Implementation

Fiona Oliver-Glasford

Global Greenhouse Gas Emissions



Source:
https://www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=54C061B5-1
https://www.ec.gc.ca/indicateurs-indicators/default.asp?lang=en&n=18F3BB9C-1

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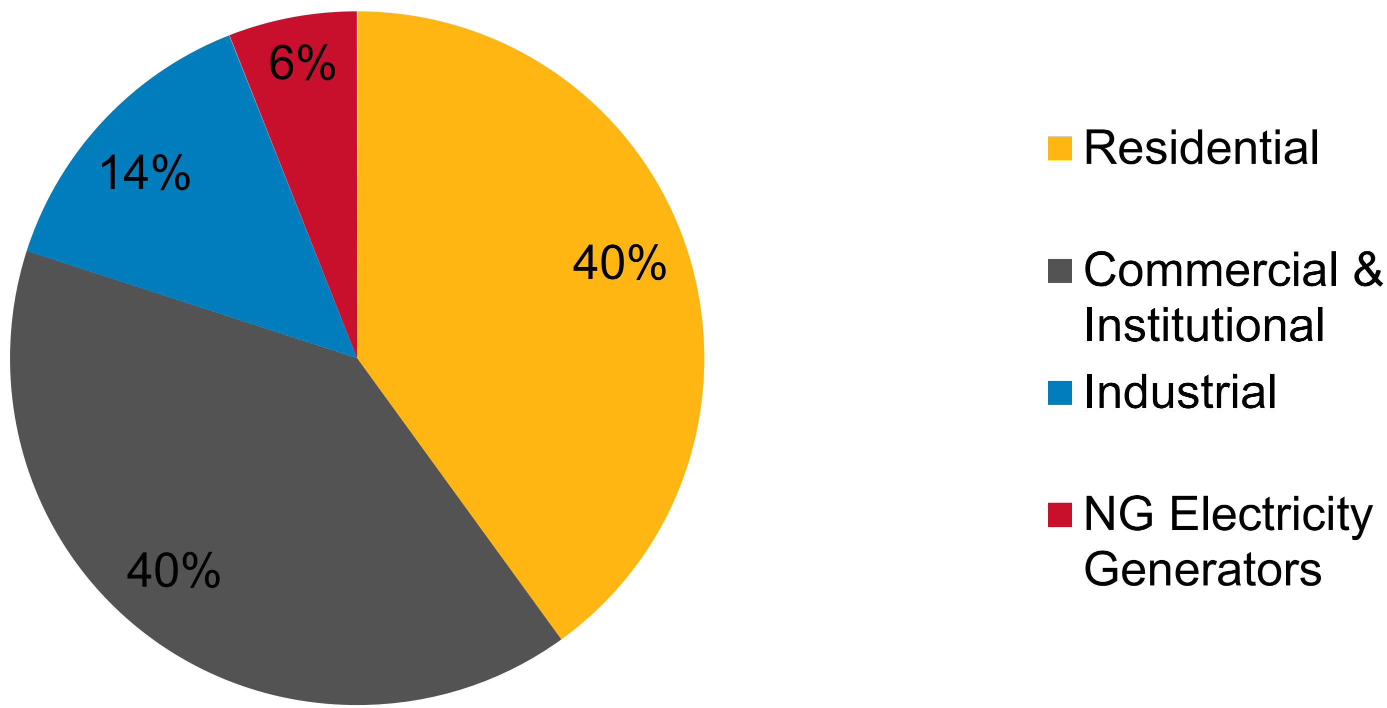
Emissions by Enbridge's Customer Type

This graph shows where emissions are derived from our customer base due to combustion of NG

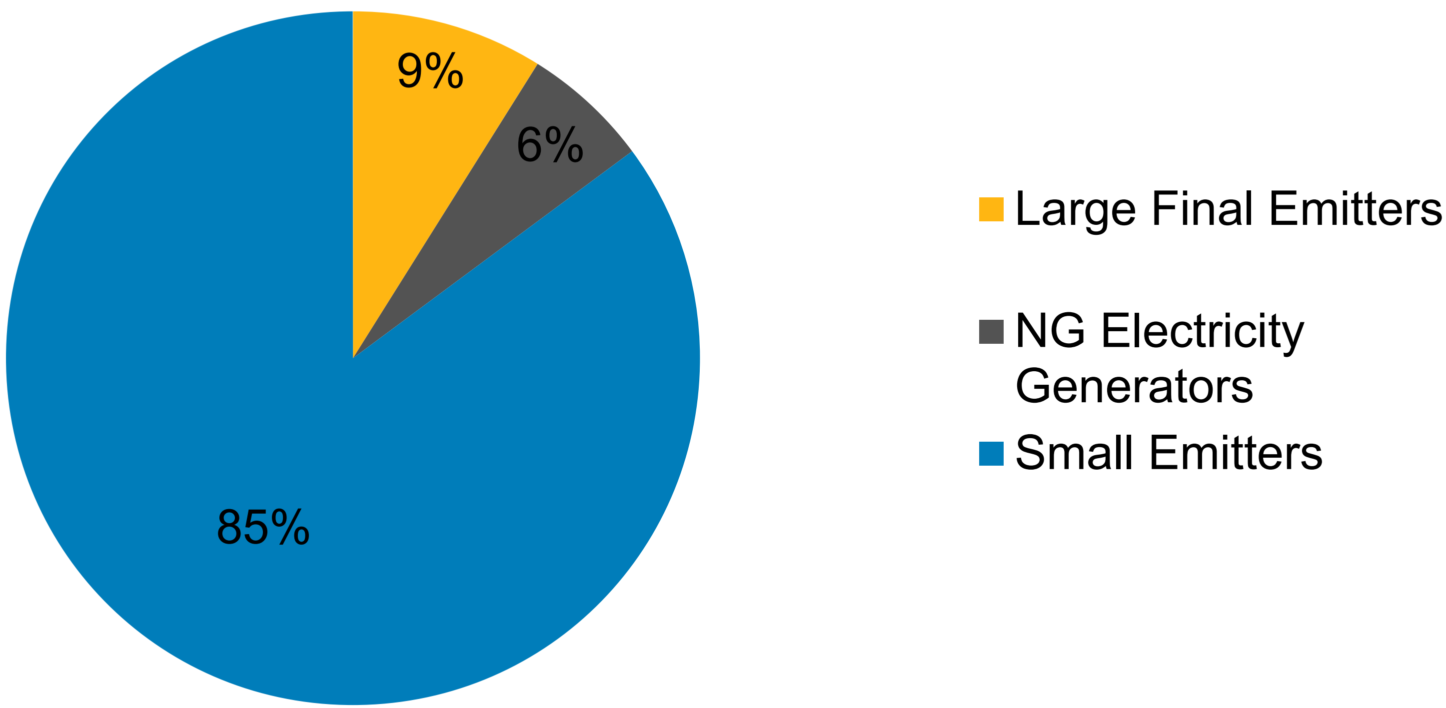
Customer Emission Profile



Emissions for Enbridge's Large Final Emitters vs. Non-LFEs

This graph shows the percentage of emissions from those under and over the 25,000 tCO_2e threshold for LFE

Large Final Emitters versus Non-LFEs



Ontario Cap & Trade Information

Draft regulations released and comments due April 10

- Under Ontario's Draft Cap & Trade Regulations, EGD expected to purchase Greenhouse Gas (GHG) Allowances on behalf of customers under 25,000 t CO_2e and NG Power Generators
  - Large Final Emitters > 25,000 tCO_2e will purchase their own allowances
  - Customers between 10,000 and 25,000 tCO_2e required to report their emissions, but EGD will purchase allowances
  - Forecast carbon credit costs range from $300-$500MM
- Enbridge anticipates recovering costs associated with Cap and Trade through a Deferral or Variance account
- The volumetric charge could be updated quarterly to reflect changes in the price of emission allowances, minimizing volatility in the charge – bill presentment TBD

Issue 1: Tight timelines

The practical matter of the utility being business ready based on current timelines are a challenge

- Regulatory Requirements
  - What is the framework?
  - Cap and Trade cost HST exempt? Understand this is still being determined by MOECC

- Opt-in decision must be known and attestation provided to NG utilities prior to December 1 (disconnect with November 30 deadline)

- Customer Communication
  - Customers must be well advised of program asap to make informed decisions
  - Must be able to communicate details to customers prior to Jan 1 start of billing

- Billing System/Bill Presentment
  - All systems
    - Billing systems presentment decisions need to be made by June 1 for successful rollout

- Other?

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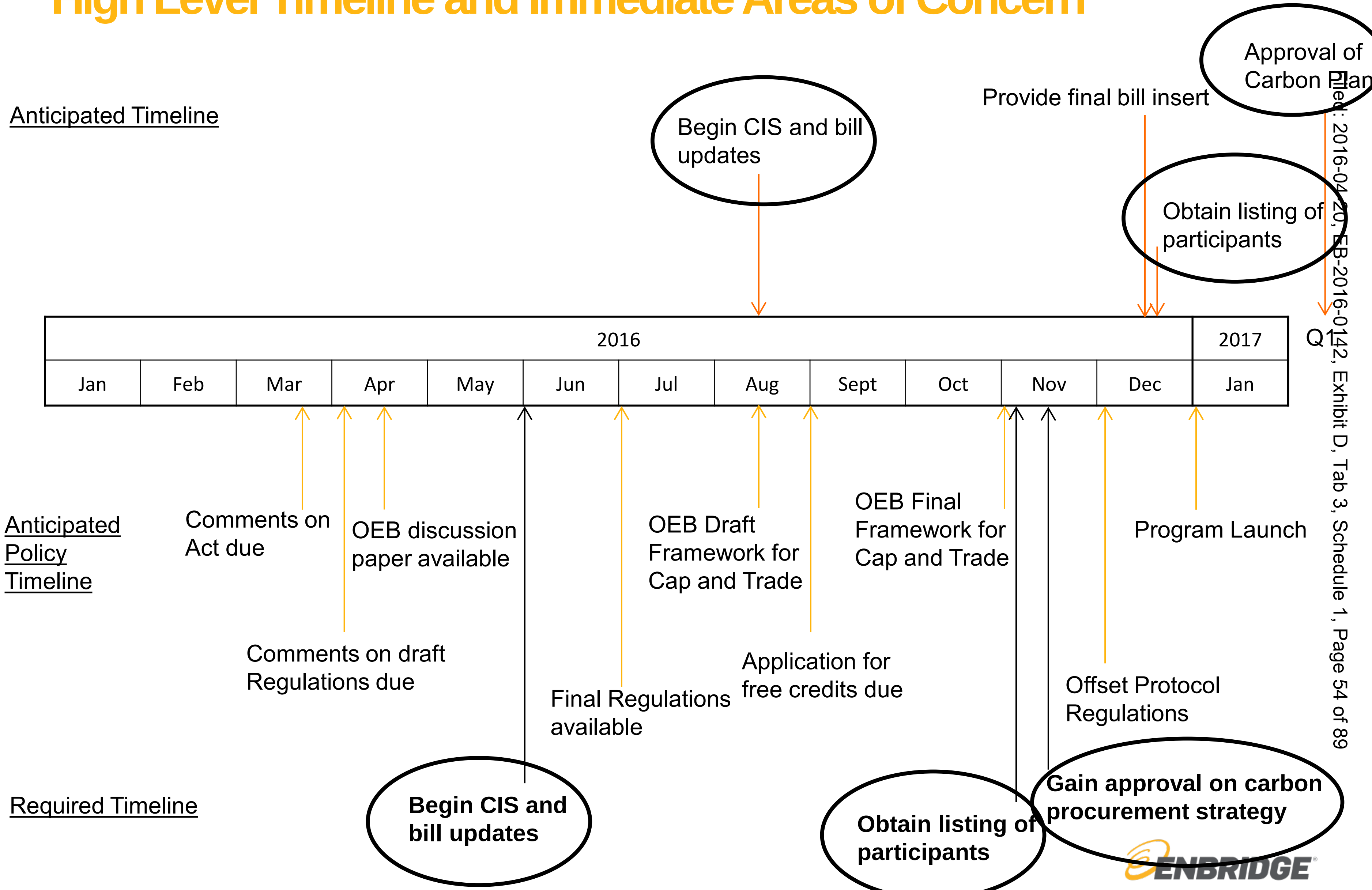
High Level Timeline and Immediate Areas of Concern



Issue 2: Purchasing & Holding Limits

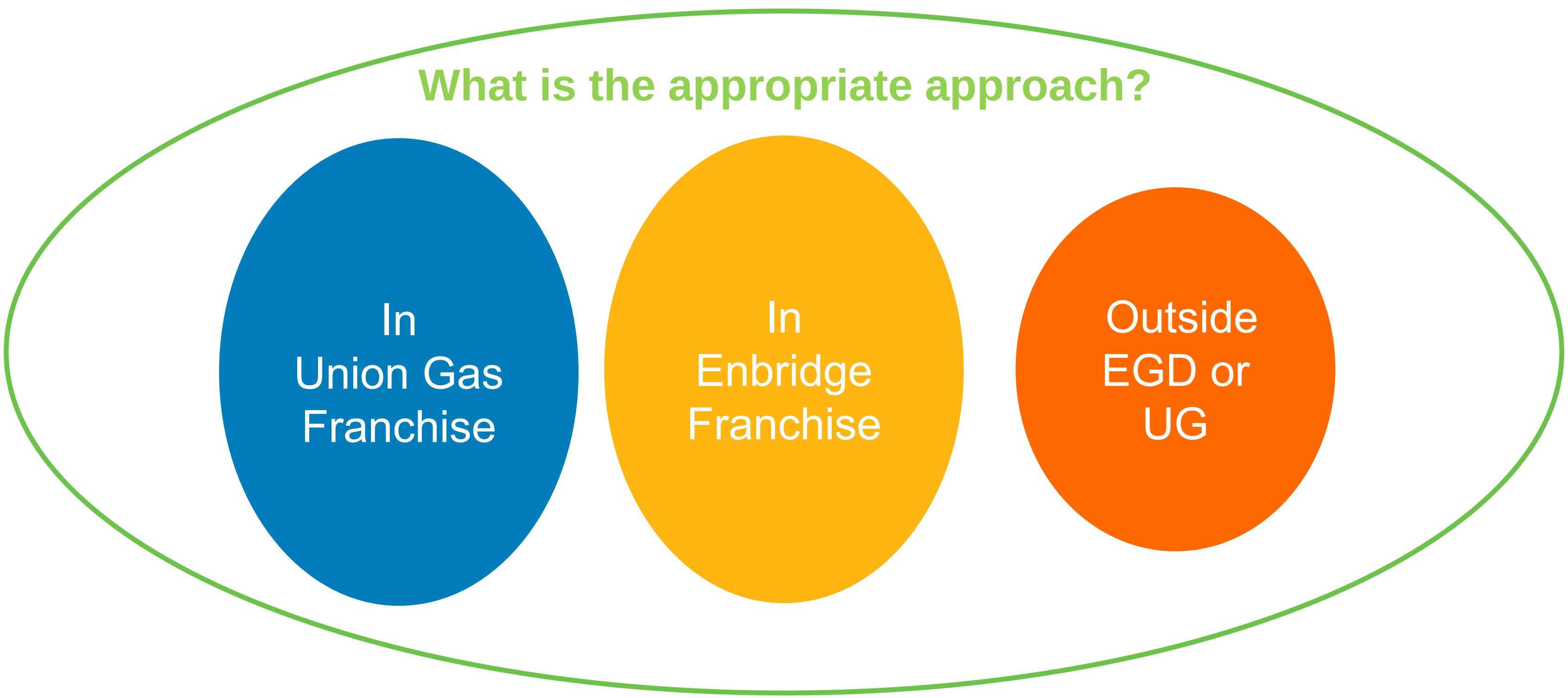
Overly restrictive for a utility that needs a good portion of the proceeds

- Limits imposed on purchasing and holding of allowances limits flexibility for Enbridge given our carbon allowance needs
- Do not account for swings related to a colder than usual winter or a nuclear plant coming offline (and NG power generation picking up the balance)
- Can only purchase up to 25% of the allowances that are available at auction
- The MOECC will create 142,332,000 allowances, but not all will be available
- In Enbridge's case the holding limit essentially becomes a purchase limit
- The lack of flexibility afforded to Enbridge limits our ability to optimize our carbon procurement

Issue 3: Power Plants

NG fired generators cannot opt in to NG utility management of allowances

– Government expressed desire for homogeneity of price and simplicity; however, draft regulation introduces complexity



Productivity & Benchmarking

Lisa Lawler
Melinda Yan

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Productivity & Benchmarking Agenda

1. 2015 Productivity Focus
2. Custom IR Capital and O&M Commitments
3. 2015 Embedded Initiatives
4. 2015 Incremental Initiatives
5. Performance Measure Results
6. Summary and Benchmarking for Total Factor Productivity

1. 2015 Productivity Focus

- **In 2015, safety and operational reliability remains the Company’s number one priority, underpinning our pursuit of productivity improvements**
- **Building on the productivity work established in 2014, the Company continued to engage all employees in productivity concepts and reporting on initiatives to facilitate reporting to the OEB, as required**
- **A number of these initiatives have been featured in internal articles and President’s Dispatches, highlighting the Company’s focus in this area and the recognition that productivity improvements facilitate success under the Custom IR framework**
- **The messaging will continue throughout the Custom IR term**

1. 2015 Productivity Focus

To qualify as a sustainable Productivity gain, the following guidelines have been used:

- **Output and / or quality must be maintained at a lower cost**
- **Output and / or quality must be improved at the same cost**
- **Productivity actions should be those that have been embedded in IR budgets or incremental savings relative to the IR budget**
- **Achievable within parameters of what was approved**

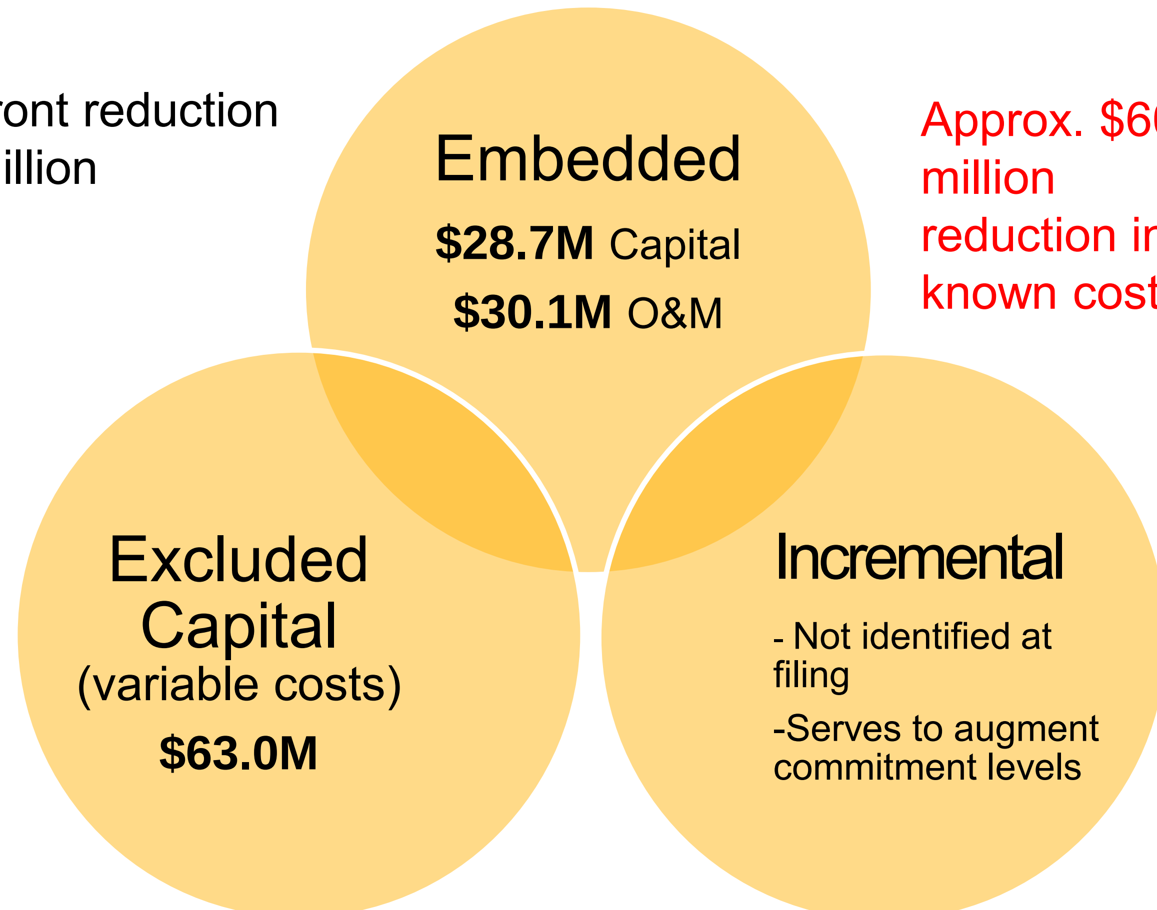
Employees were encouraged to report even small initiatives. No materiality threshold was defined

This resulted in over 100 reported initiatives, which underpin the remainder of the presentation

2. Custom IR Capital and O&M Commitments

2015 Productivity Commitments

Total up-front reduction of $123 million



Approx. $60 million reduction in known costs

2. Custom IR Capital and O&M Commitments

IR Budgets & EGD's Productivity Commitment

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 Reduction	(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)	(264.5)
Approved Core Capital Expenditures	443.8	446.6	441.9	441.9	441.9	2,216.1

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 Reduction	(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

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3. 2015 Embedded Initiatives

O&M and Capital Embedded Productivity Results

	2015 Estimated Savings Relative to Embedded O&M and Capital Reductions	Committed ($M)	Actual ($M)
1.	O&M: Merit increase	(2.0)	(0.4)
2.	O&M: Employee Benefits	(2.2)	(0.4)
3.	O&M: Incremental cost to service new customers	(1.6)	1.3
4.	O&M: Incremental safety and integrity work	(9.1)	(2.0)
5.	O&M: External contractor rate increases	(1.4)	(0.4)
6.	O&M: Increased volume of locates-compliance with Bill 8	(3.2)	(2.1)
7.	O&M: FTEs	(5.7)	(8.2)
8.	O&M: Bad Debt expenses	(5.0)	(4.5)
9.	Total Estimated O&M Savings	(30.2)	(16.7)
10.	Capital: Customer Attachments	(25.5)	(13.8)
11.	Capital: Departmental Labour	(3.2)	(11.6)
12.	Total Estimated Capital Savings	(28.7)	(25.4)
	Total Estimated Embedded O&M & Capital	(58.9)	(42.0)

4. 2015 O&M Incremental Initiatives ($10.2M)

Sustainment and full year effectiveness of 2014 results plus new incremental initiatives

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

Labour Optimization	• absorption of work through existing labour capacity, reallocation of tasks and skill sets	$1.6 million
Process Optimization	• system changes, efficient work flows, streamlined tools, eliminated redundancy	$5.7 million
Materials/Space/ Equipment Rationalization	• space optimization, efficient use of materials, supplies, equipment	$2.1 million
Policy Changes & Improvements	• changed manner in which services were contracted or delivered to optimize existing resources	$0.8 million

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4. 2015 Capital Incremental Initiatives ($5.9M)

Process Optimization	• system changes, efficient work flows, streamlined tools, eliminated redundancy	$2.0 million
Materials/Space/ Equipment Rationalization	• space optimization, efficient use of materials, supplies, equipment	$3.2 million
Policy Changes & Improvements	• changed manner in which services were contracted or delivered to optimize existing resources	$0.7 million

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5. Productivity Measure Results

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

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5. Operational Performance Measure Results

All Operational Performance metrics are achieving strong performance

Operational Performance	2013	2014	2015 (DRAFT)	Trending
1. Employees Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	1.06	↑
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	2.43	↑
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.06	0.06	↔
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	905	↔
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	4.84	↑

↑ – Improving
↔ – Stable
↓ – Decreasing

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5. Customer Relationship Performance Measure Results

All Customer Relationship metrics are achieving strong performance

Customer Relationship Performance	OEB Target	2013	2014	2015 (DRAFT)	Trending
1. Overall Customer Satisfaction Index	NA	78%	77%	79%	↑
2. Call Answering Service Level (SQR)	75%	75.9%	79%	80%	↑
3. Percentage of Emergency Calls Responded to within One Hour (SQR)	90%	96.1%	96.9%	96.7%	↔
4. Appointments Met within the Designated Time Period (SQR)	85%	94.2%	95.1%	95.2%	↑
5. Time to Reschedule a Missed Appointments (SQR)	100%	95.0%	95.5%	94.8%	↔
6. Number of Days to Reconnect a Customer (SQR)	85%	92.6%	94.0%	94.6%	↑
7. Number of Calls Abandon Rate (SQR)	10%	2.8%	1.9%	2.4%	↔
8. Meter Reading Performance (SQR)	0.5%	0.5%	0.69%	0.50%	↑
9. Number of Days to provide a Written Response (SQR)	80%	94.5%	93.3%	100.0%	↑

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6. Summary and Benchmarking for Total Factor Productivity

- The Company achieved excellent results in 2015, both in terms of productivity improvements and in delivering value to customers, underpinned by our number one priority of safety and operational reliability

- With respect to Enbridge's Benchmarking Commitment, the Company will:
  - Engage a third-party consultant to conduct a Total Factor Productivity report
  - Conduct a consultative to review Enbridge's proposed benchmarking methodology with intent of filing an acceptable approach with the OEB
  - This must be completed such that the final report is filed prior to the end of Custom IR period

- Next steps
  - Prepare a Request for Proposal (RFP), Evaluation Matrix and review proposed respondents
  - Solicit stakeholder comments for consideration
  - Issue RFP before the end of 2016

Asset Management

Trevor MacLean

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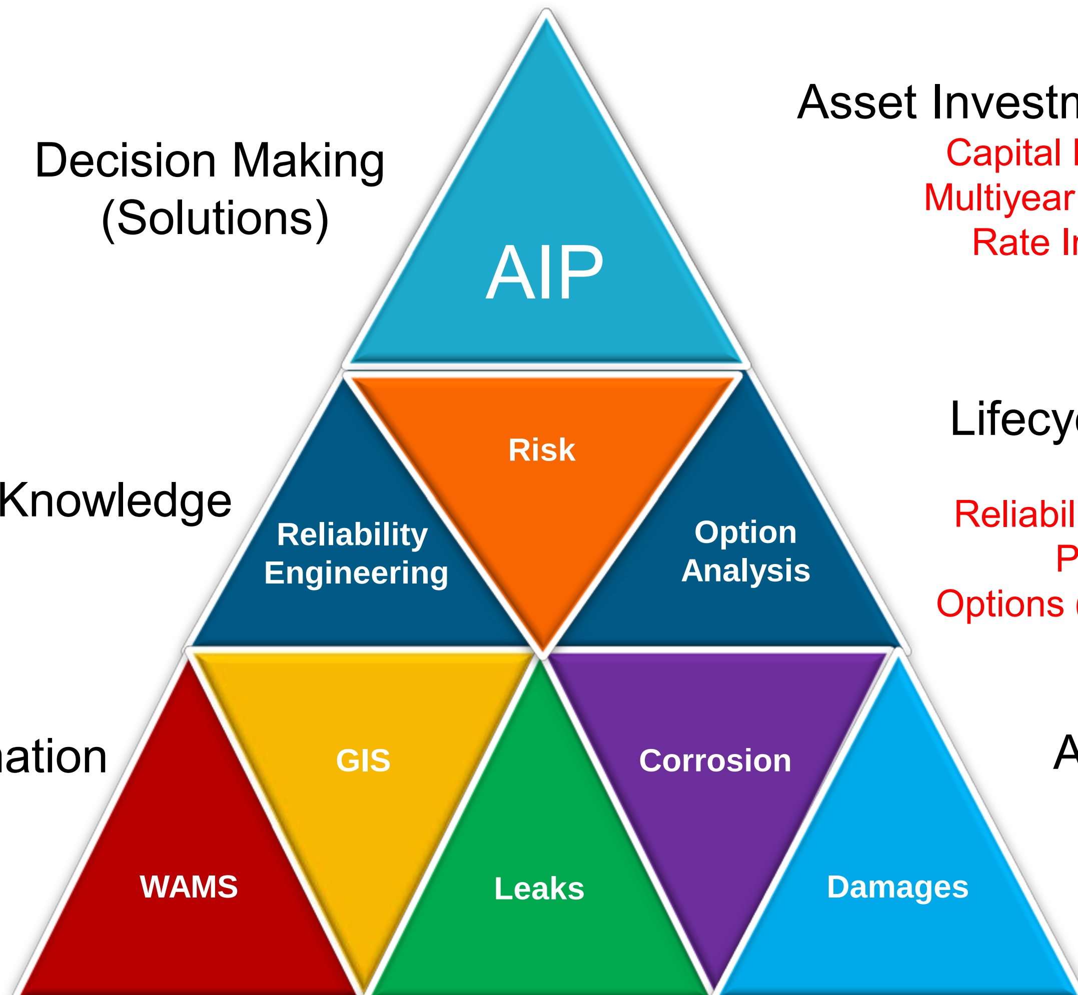
Asset Management Overview

Knowledge → Decision Making (Solutions)

Information → Knowledge

Data → Information



Asset Investment Planning
Capital Planning
Multiyear Tradeoffs
Rate Impacts

Lifecycle Strategy
Risk
Reliability Engineering
Prediction
Options (Capex & Opex)

Asset Information
Condition
Probability of Failure

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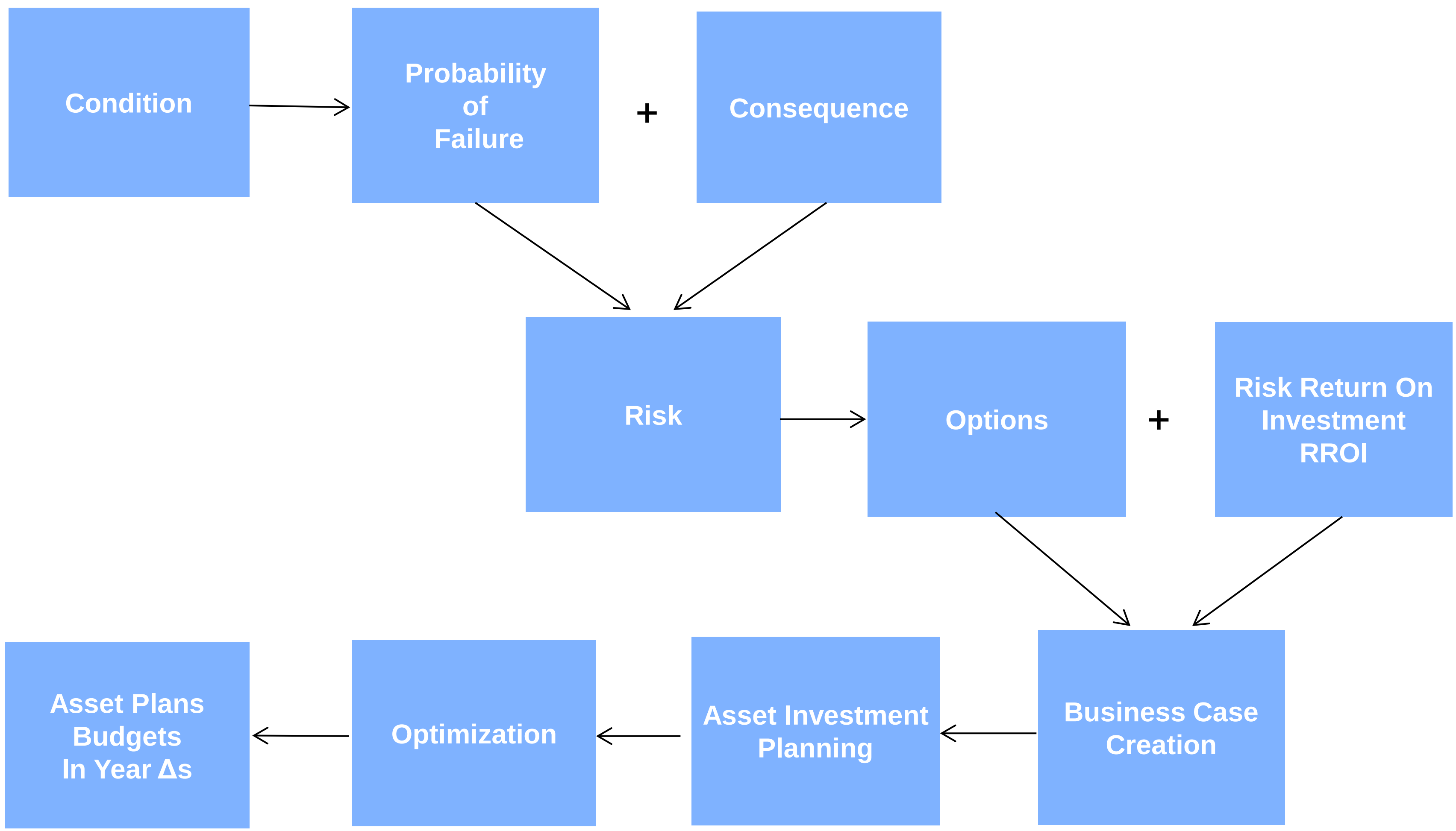
Simplified Asset Management Process



Condition & Probability of Failure

Principles:

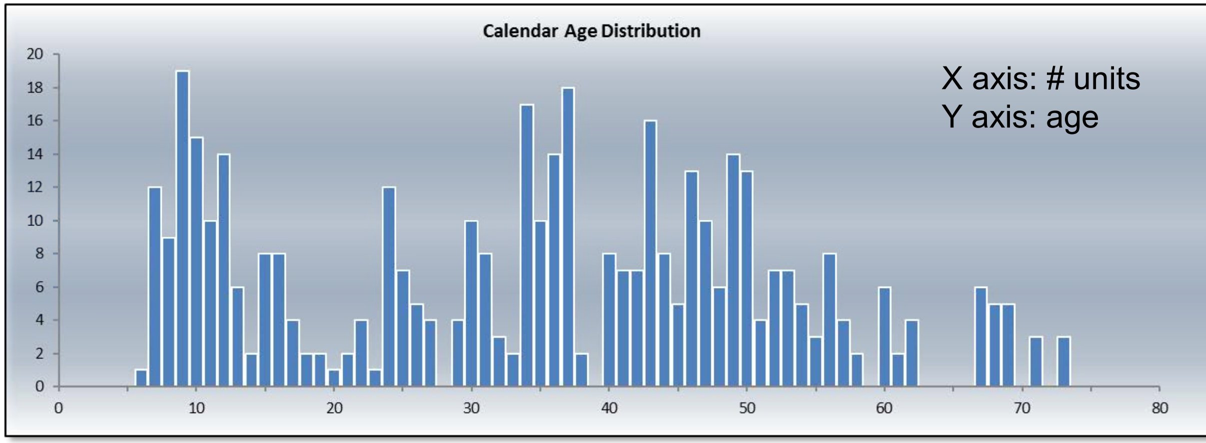
- Condition is not simply a matter of age
- Probability of Failure is a function of Exposure, Mitigation & Resistance

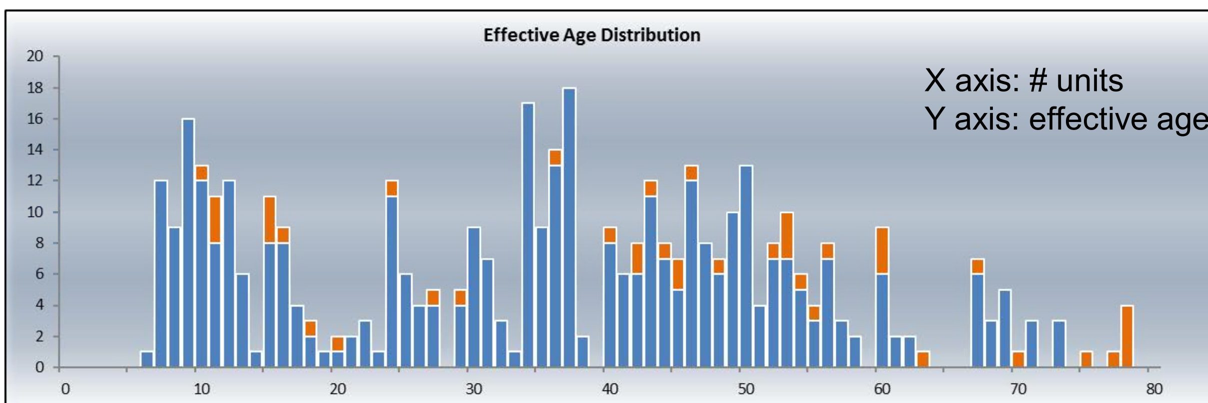
Primary Actions:

- Comprehensive Asset Health Review & sustaining methodology (UMS was selected via RFP in 2015 with completion summer 2016)
- Best available data sourced from EGD, Industry, UMS (ongoing)
- Data Lake initiative to integrate all condition source information in a single repository with completion end 2016
- Central platform for housing risks, lifecycle curves, degradation factors (RIVA DS/Decision Support via RFP in 2015 with completion end 2016)

Asset Health Review Details

Example of Model Initial Outputs – Age vs. Effective Age





Probability Of Failure – Simplified Example

Steel Pipe

Failure Mechanism	Exposure	Mitigation – Owned by Enbridge	Resistance
External Corrosion	• Soil • Atmosphere • Water	• Coating (e.g. quality of coating; number of field applied coating) • Cathodic Protection	• Wall thickness • SMYS
Third Party Damage	• Excavators • Vehicles • ROW	• Depth of Cover • Casing • Signs • Patrol	• Wall toughness • Wall thickness
Geo-hazard	• Landslide • Flood • Erosion	• Stabilization • Ground Improvement	• Stresses • Loads

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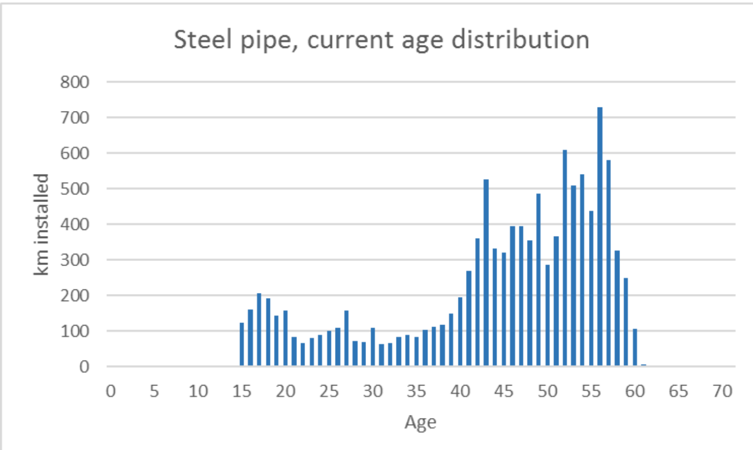
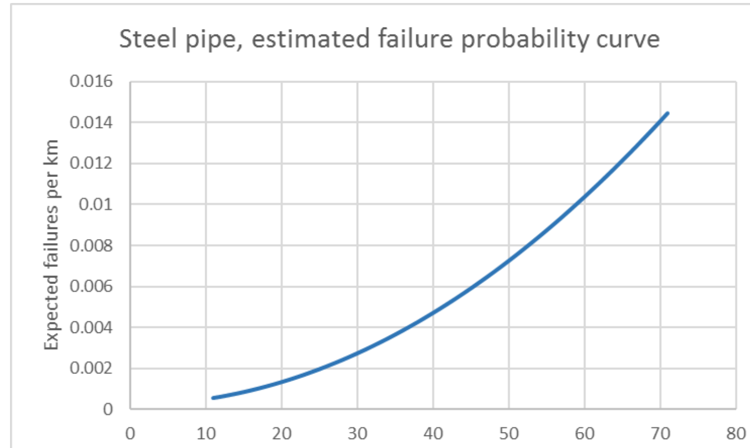
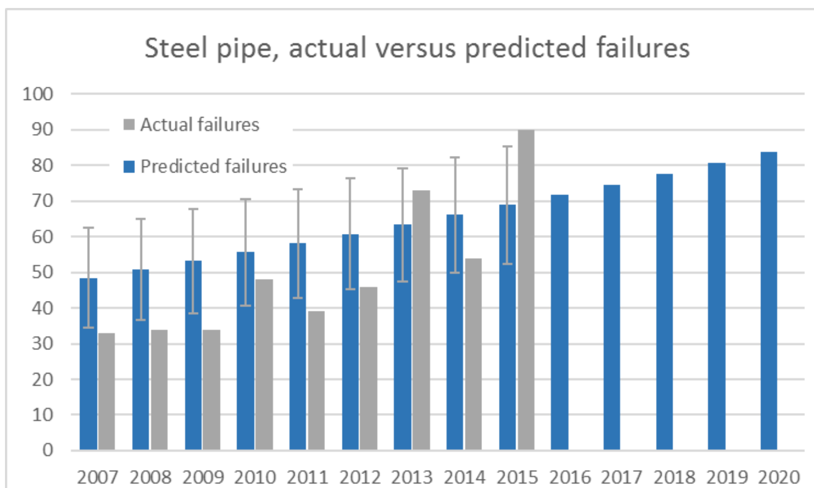
Asset Health Review Details

AHR Model Initial Outputs – Steel Pipe Asset Sub Class – Failure Projections







riva

MASTER SBX : Derek Polson

Main ▾ Tools ▾ Session ▾ Help

Actions | Home | Asset Tree | MAIN-105:1037:1078

MAIN-105:1037:1078

View: Basic

Name	MAIN-105:1037:1078	Title	MAIN-105:1037:1078
Asset Type	Main	Active Date	1968-09-01
Rollup To	Site 380	Retirement Date	
Status	Active	Riva Asset Code	15712

Identification

PMTS Asset ID	434	Admin Area Code	10
High Node	1,078	Low Node	1,037
Municipality 1	TORONTO	Corrosion Area Num	J9050
Network	105		

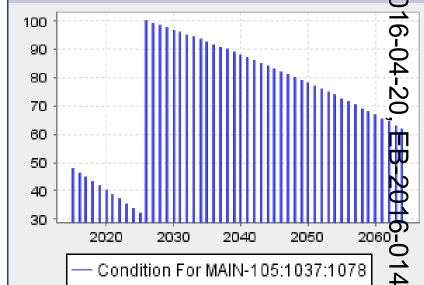
Lifecycle

Useful Life	75	Current Age	48
Remaining Life	27	Life Consumed (%)	64
Asset Health Index		Date Manufactured	
Date Installed			

Asset Details

Vital Point	N	Current Length (m)	236.3
Bridge Crossing	N	Rail Crossing	N
Easement	N	Private Property	N
Orig Wall Thickness	0	Orig Nominal Pipe Size (in)	12
Max Allowable Pressure		Joint Trench	N
Manufacturer		Heat Num	
Notch Tough Cat		Wall Thickness	6.4
Spec Min Yield Stren Val	290	Pipe Coating Desc	YELLOW JACKET
Nominal Pipe Size (in)	12	Short Desc	SC - PIPE STEEL NPS 12 WT 6.4MM

Condition



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Consequence & Risk

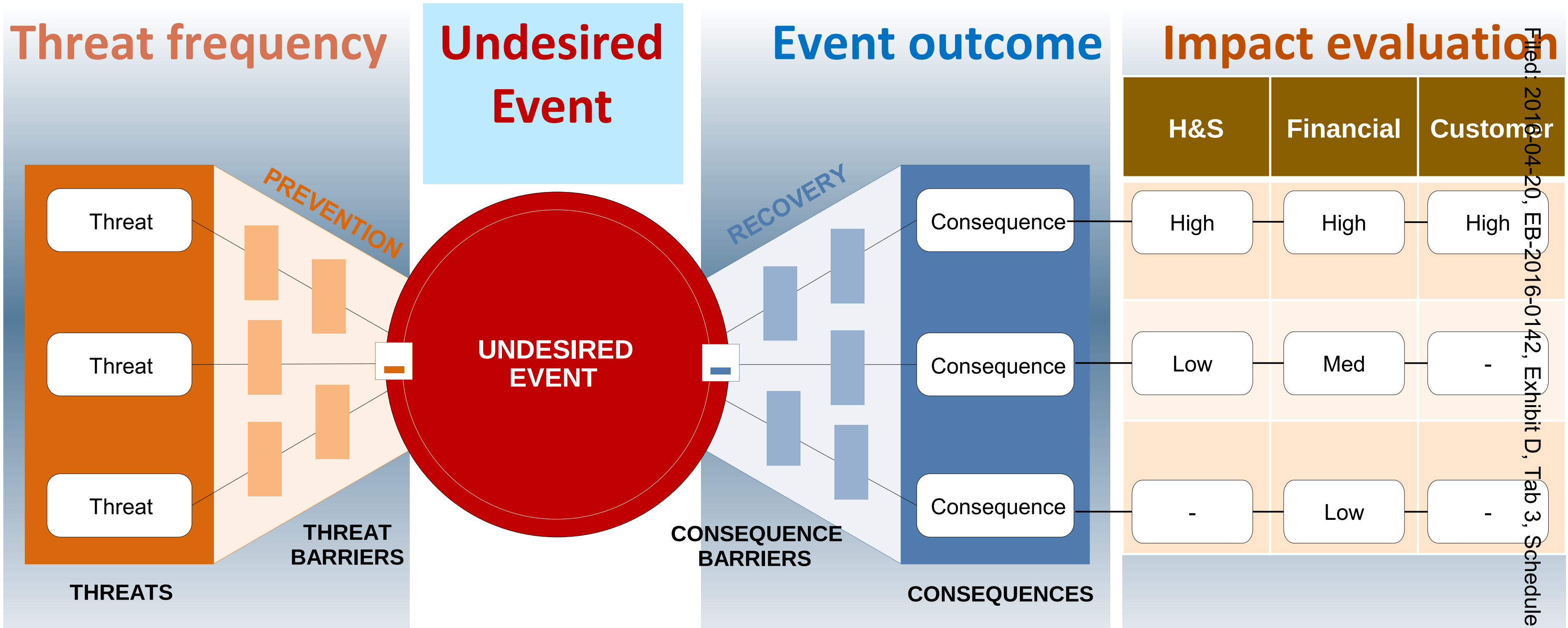
Principle:

- Quantitative risk assessment (QRA) results in a better understanding of individual risks and comparability between them than qualitative review

Primary Actions:

- Adopted Bowtie analysis as the primary approach to QRA
- Assembled risk team with extensive experience
- Centralized our operational risk register in RIVA to seamlessly connect risk, lifecycle planning, option analysis & investment planning
- Adopted risk return on investment as an asset decision metric

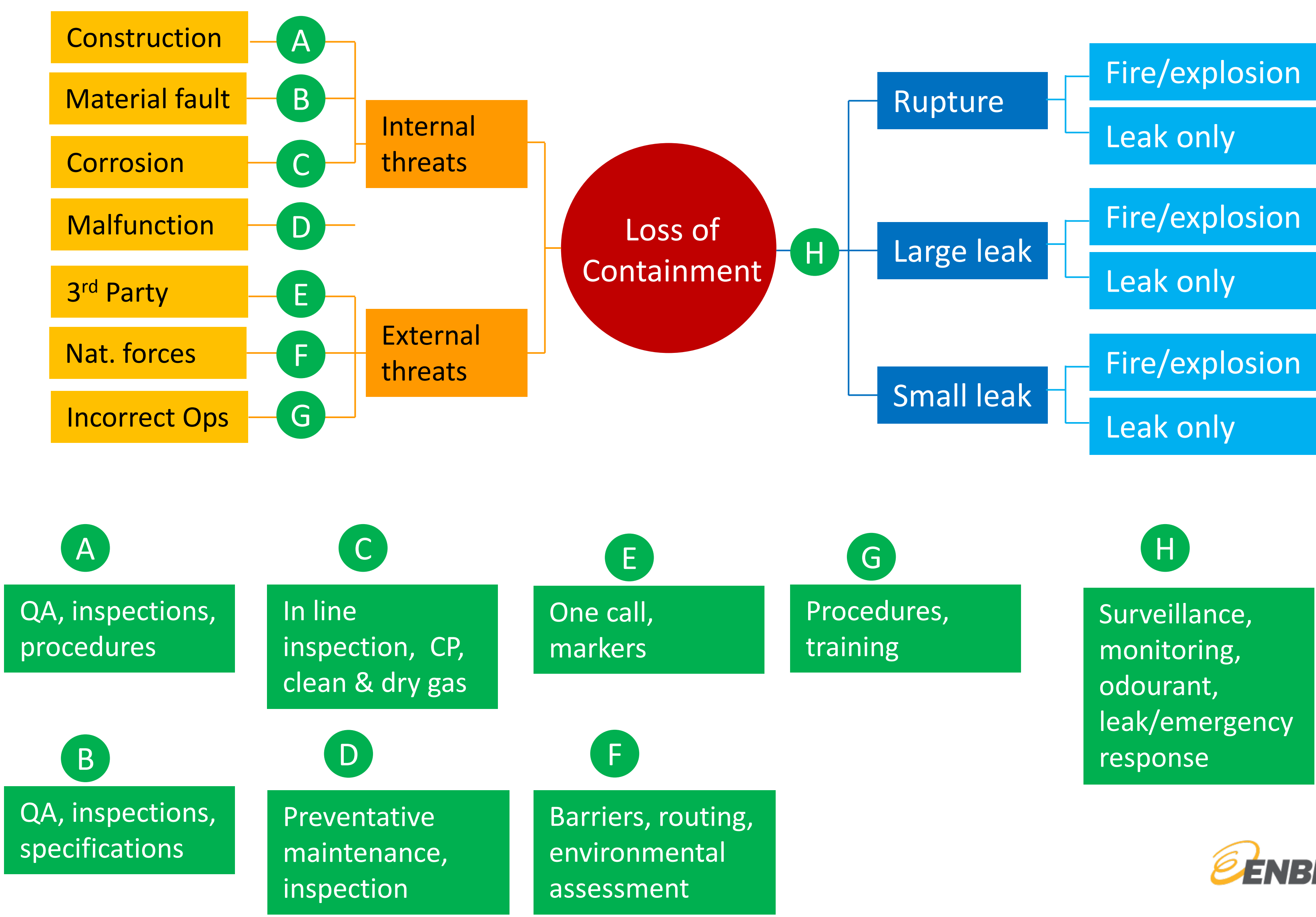
Risk Model



- Move from *weighted qualitative* ratings of risk indicators to *quantitative* results of risk models
- Bow tie models used to determine all risks (with the left side comprising frequency assessment and right side comprising risk outcome assessment for defined hazard)

Generic bowtie model for pipeline

This diagram is illustrative only: this is not a comprehensive list of the threats and safety measures



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Options, RROI, Business Cases

Principles:

– All requirements for capital must have a business case
  - Tied to a risk or opportunity/benefit (O&M in scope at times e.g. repair/replace)
  - At least two options that quantify Δ risk or Δ benefit independently, where possible
– RROI is the primary basis for comparison except when:
  - At an absolute risk tolerance threshold - risk mitigation will occur independent of cost,
  - A compliance issue is identified - tied to a specific code/approved by Engineering, or
  - A mandatory requirement exists via authority of another agreement, e.g. relocations

Primary Actions:

– Acquired RIVA CP(Capital Planning) to house business cases and link risk, options, business cases, asset investment planning together
– Gas carrying assets were in-scope in 2015, all other assets in 2016

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Risk Register to Business Case

Risk List

Asset Class
Total Risk To Null Values
Risk Type
Status
Search Clear Search Add To Search >>

Rows 1 to 392 of 392

Asset Class	Risk Name	Total Risk 2	Issue/Concern	Compliance	Status 1
Customer	Regulator and Meter Exchanges(MXGls)	4,316,543	Main Concern: Over Pressure, Gas escape, Customer billing. "Regulator	Y	Business Case
Pipeline	Reinforcement: York Region (Bathurst Gate to Mulock) (Screening and Pl	3,351,334	Business case is for planning seed money only. Construction phase to t		Business Case
Stations	2016 Pressure Recorder Program	2,244,366	Spend for the purchase of equipment for the replacement of the paper c		Business Case
Pipeline	ILI Program: Upsize for Keele	1,365,166	The scope of this project is the replacement of 508m of NPS26 main wit		Business Case
Pipeline	2016 Blanket Relay - All Areas	807,500	This Business Case is created to group all Blanet Relay IDFs for all 7		Business Case
Pipeline	Reinforcement: Peterborough (Preston/Hwy 7)	794,260	System growth necessitates the need to reinforcement.		Business Case
Pipeline	Corrosion: Copper Services	720,961	An engineering assessment was conducted in 2004 on the Copper Relays P		Business Case
Stations	Odorant Solution	719,606	CSA Z662 mandates that natural gas in distribution systems shall have		Business Case
Pipeline	Reinforcement: Mavis/Rathburn/Confederation , Mississauga	572,902	The following gas mains are required in 2016 to support the rapid grow		Business Case
Pipeline	Reinforcement: NW250 (Year 2 - 2016)(Fifshire Rd to Gerald St)	568,000	Irregular growth patterns are happening in NW250 - homeowners are tear		Business Case
Storage	Engine Block Replacement Program K706	540,005	Due to the age of the infrastructure and hours operating, replacement		Business Case
Pipeline	Reinforcement: 7656 Bramalea	450,000	1. Emerald Power is requesting 250psi for co-gen facility, 2. Enbridge	Y	Business Case
Pipeline	2016 Blanket Replacement - All Areas	446,906	Through out the year there is a need to expedite short main replacemen		Business Case
Pipeline	Cross Bores - Mechanical Spring	441,620	Require tools to detect the presence of sewer laterals during HDD inst		Business Case
Pipeline	Reinforcement: Collingwood	410,432	Inadequate supply pressure to serve new customers		Business Case
Stations	Telemetry Related 2016	405,523	The Telemetry system is vital - it's required to monitor and control o		Business Case
Stations	District Station Rebuilds 2016 - Program	377,296	The stations identified in this buisness case fall into one of the bel		Business Case
Pipeline	Reinforcement: NPS 8 XHP River Rd / Strandherd	366,000	NPS 8 XHP Reinforcement project - incudes a crossing of the Rideau Riv		Business Case
Pipeline	Pipeline Risk and Integrity Management Evaluation tool (PRIME tool)	363,640	GSTSI has been using a software tool for pipeline integrity and risk a		Business Case
Stations	M&R Technology Management Project (Station Records)	359,340	The M&R Technology Management Project is implementing a Management of	Y	Business Case
Pipeline	Pressure Elevation: Thornton Gate (Planning)	328,975	Thornton Gate Pressure Elevation (Baxter/Borden Line & Innisfil Line,		Business Case
Storage	Crowland Well Replacement (Execution)	277,089	There are currently 24 wells in the Crowland DSA. Wells currently have	Y	Business Case
Pipeline	Forks Rd, WAIN - Inaccessible main	254,560	Exisitng main is not accessible as its below a swamp within easement c		Business Case
Pipeline	NPS 30 Don Valley Bridge remediation work	244,259	The NPS 30 Don Valley line is a critical feed that supplies gas to dow		Business Case
Pipeline	Pressure Elevation: Niagara Falls IP NW8320	242,843	The following gas main and stations are required:1. Increase the Black		Business Case
Pipeline	Records: Record Digitization - 2016	227,654	The focus of this track of work is to digitize priority historical pap		Business Case
Pipeline	ILI Program: NPS 24 Metrowest Ph I & II (Screening & Planning)	194,898	This business case is to request capital to retrofit the two NPS 24 Me		Business Case
Pipeline	MOP Program 2016 - Program	173,559	Ensuring verifiable, traceable and complete records identifying that p	Y	Business Case
Pipeline	ILI Program: NPS36 GTA - Immediate Digs	153,918	NPS36 GTA Integrity Dig Program - This Capital Business Case template	Y	Business Case
Stations	NPS30 Launcher/Receiver for NPS30 Lisgar to Keele Inspection - prespen	148,966	This project is the purchase of a NPS30 launcher and receiver to inspe		Business Case
Pipeline	DOC: St Paul St. STC	130,464	Existing NPS 6 and 4 steel LP main is very shallow (0.7m to 0.4m cover	Y	Business Case

Business Cases & RROI

IDF Number	Name	Asset Class	Risk Mitigated	RROI (%)
5,067	York Region Reinforcement (Screening and Planning)	Pipe	2,697,584	529
13,993	2016 Pressure Recorder Program	Stations	2,136,083	118
11,941	30.11458582.16 Upsize for Keel	Pipe	1,308,471	41
15,533	2016 Blanket Relay - All Areas	Pipe	807,500	10
14,247	Regulator and Meter Exchanges	Customer Assets	724,776	5
11,601	40.9908453.13 Peterborough Rei	Pipe	685,387	49
14,903	Odorant Solution	Stations	631,330	210
9,561	NW250 (Year 2 - 2016)	Pipe	568,000	167
13,483	Mississauga Downtown Reinforcement	Pipe	553,394	70
8,664	20.11541137.15 7656 Bramalea	Pipe	450,000	65
15,531	2016 Blanket Replacement - All Areas	Pipe	446,906	10
12,843	Engine Block Replacement Program K706	Storage	424,729	18
13,407	Collingwood Reinforcement - Planning	Pipe	410,378	249
7,223	NPS 8 XHP River Road / Strandherd Reinforcement	Pipe	366,000	9
13,990	Telemetry Related 2016	Stations	354,009	21
15,282	District Station Rebuilds 2016 - Program	Stations	329,790	5
3,587	Thornton Gate Pressure Elevation - Planning	Pipe	328,975	292
13,547	M&R Technology Management Project (Station Records)	Stations	323,739	14
13,982	Cross Bores - Mechanical Spring	Pipe	320,612	256
14,002	Forks Rd, WAIN	Pipe	252,431	28
14,187	Crowland Well Replacement (Execution)	Storage	249,380	19
13,462	Niagara Falls IP NW8320 Pressure Elevation	Pipe	236,228	13
14,941	Pipeline Risk and Integrity Management Evaluation tool (PRIME tool)	Pipe	176,304	10
14,202	MOP Program 2016 - Program	Pipe	173,559	10
14,721	NPS30 Launcher/Receiver for NPS30 Lisgar to Keele Inspection - prespend	Stations	142,780	41
13,824	Copper Service Replacement	Pipe	133,033	9
13,964	St Paul St. STC	Pipe	130,201	45
4,836	MOP Program 2016 - Records	Pipe	123,596	10
14,162	2016 Depth of Cover Mitigation Work	Pipe	118,360	8
4,981	Richmond Hill Gate Station Upgrading	Stations	112,815	14
13,581	Seckerton Meter Station Filter Separators	Storage	107,185	29
13,761	Blackhorse Gate Station : Replace Welker Jet Regulators	Stations	107,152	214
12,883	EGS Control Room Migration	Storage	104,503	4
15,941	NPS36 GTA - Immediate Digs	Pipe	103,918	32
4,107	300 Steelecase	Pipe	97,309	49
15,663	Crowland Well Replacement (Planning)	Storage	97,224	19
14,251	Campbellford Replacement Project	Pipe	94,459	27
15,532	2016 Blanket Anode - All Areas	Pipe	93,409	10
19,401	MacPherson-Molson-Roxborough Replacement	Pipe	84,789	5
15,861	Pelham Gate Station Rebuild	Stations	84,000	10

Investment Planning & Optimization

Principles:

- Each option will proceed to investment planning & optimization
- RROI is the primary basis for optimization (except as noted previously)
- Multiple constraints will be set for optimization including cost/budget, RROI limits, resource availability, timing/multiyear planning
- Sub-portfolios may have individual constraints e.g. PI customer adds
- Rate impact will be a global constraint at the overall portfolio

Primary Actions:

- Utilize RIVA/CP visual leveler to perform optimization through linear programming and monte carlo simulation
- Conduct dynamic ‘what if’ analysis to account for constraints such as budget, rate impact, risk tolerance

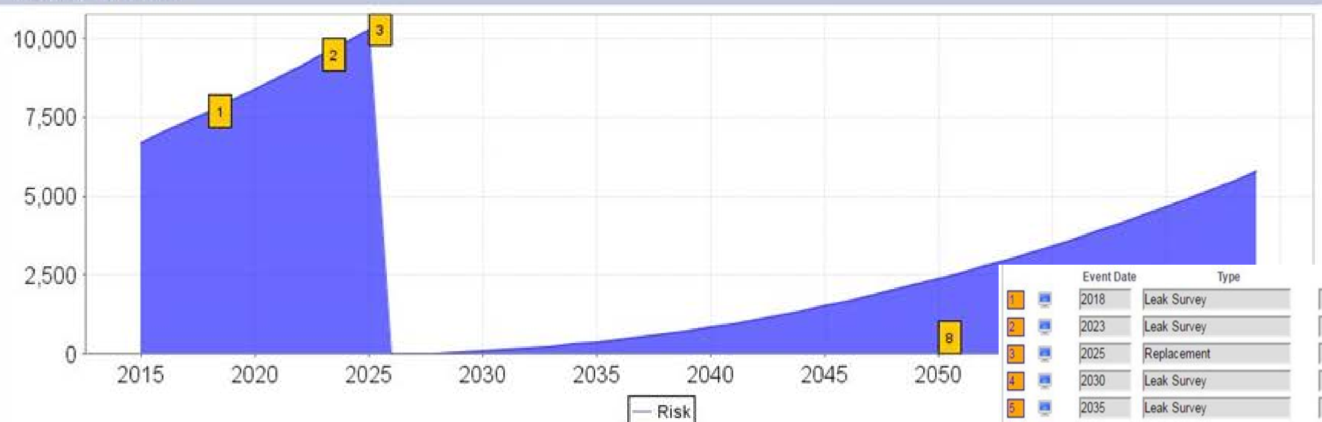
Actions | Home | Asset Tree | Mains | MAIN-146:955:956

MAIN-146:955:956

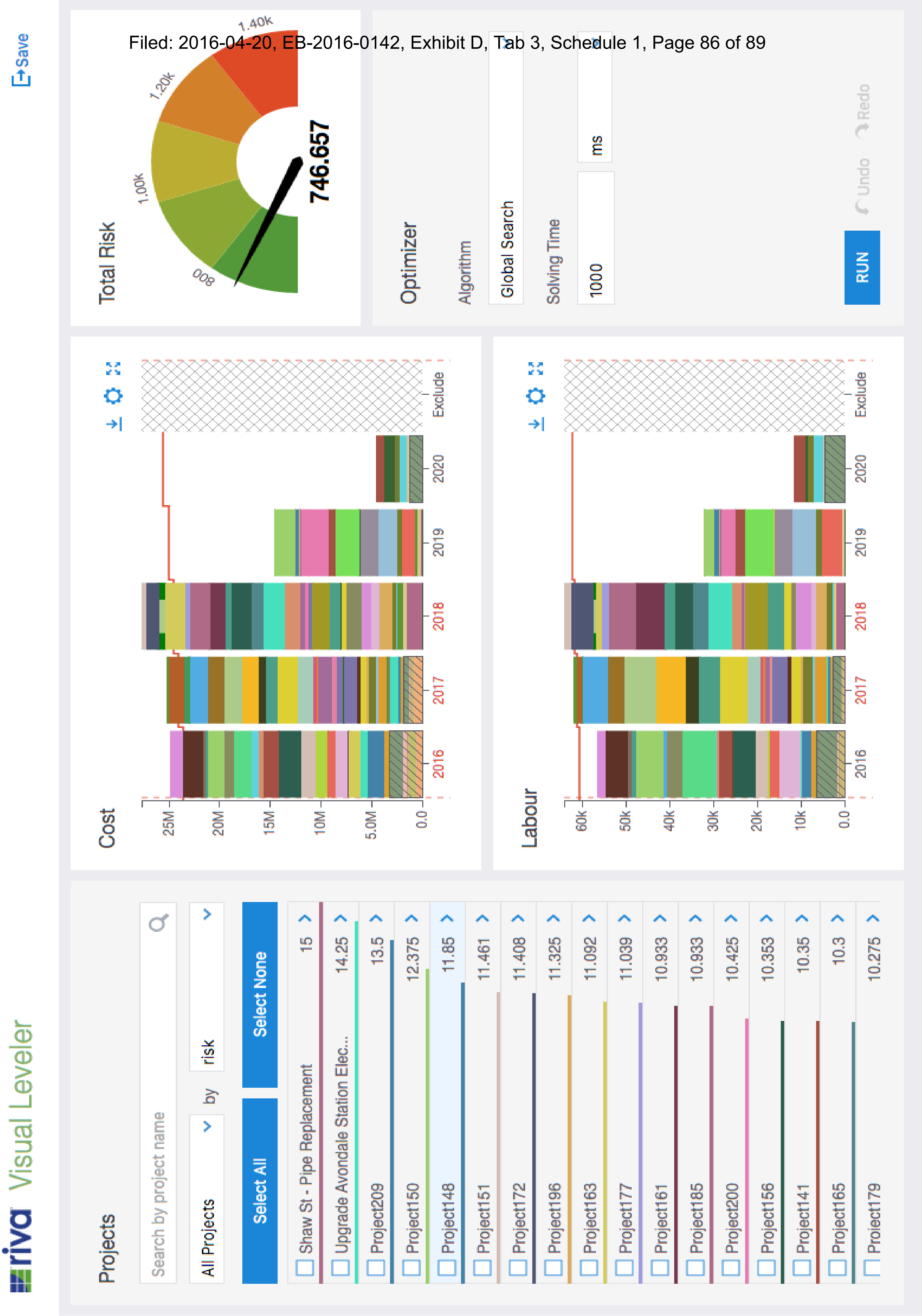
Measure Values

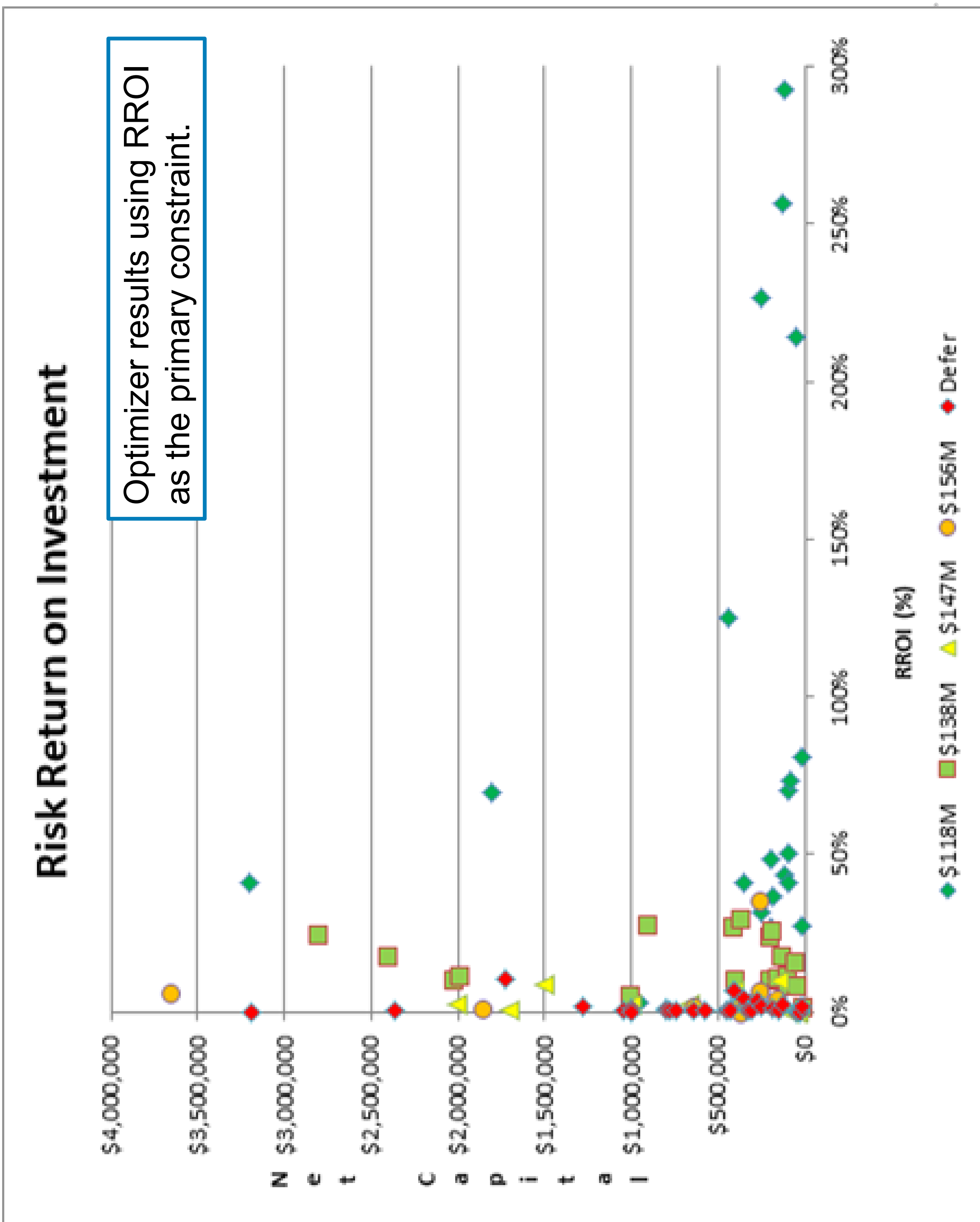
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Condition										
Lifecycle										
Age	43	44	45	46	47	48	49	50	51	0
Inspection Age	2	3	4	5	6	7	8	9	10	11
POF	1,849	1,936	2,025	2,116	2,209	2,304	2,401	2,500	2,601	0
Costs										
CAPEX					0					5,182,000
OPEX			285.01					285.01		
Cost			285.01		0			285.01		5,182,000
Asset Value										
Replacement Value	5,182,000	5,182,000	5,182,000	5,182,000	5,182,000	5,182,000	5,182,000	5,182,000	5,182,000	5,182,000
Risk & Prioritization										
Risk	7,026.2	7,356.8	7,695	8,040.8	8,394.2	8,755.2	9,123.8	9,500	9,883.8	10,275.2
Do Nothing										
Age - Do Nothing	42	42	42	42	42	42	42	42	42	42
Condition - Do Nothing	55	53.6	52.2	50.7	49.3	47.8	46.4	44.9	43.3	100
PoF - Do Nothing	0.578	0.592	0.606	0.621	0.634	0.648	0.661	0.675	0.69	0
Risk - Do Nothing	2.196	2.25	2.302	2.358	2.409	2.464	2.513	2.566	2.621	0.001

Lifecycle Events



	Event Date	Type	Project	Priority	Cost	CAPEX	OPEX
1	2018	Leak Survey		0	285.01		285.01
2	2023	Leak Survey		0	285.01		285.01
3	2025	Replacement		0	5,182,000	5,182,000	
4	2030	Leak Survey		0	285.01		285.01
5	2035	Leak Survey		0	285.01		285.01
6	2040	Leak Survey		0	285.01		285.01
7	2045	Leak Survey		0	285.01		285.01
8	2050	Leak Survey		0	285.01		285.01
9	2055	Leak Survey		0	285.01		285.01
10	2060	Leak Survey		0	285.01		285.01


riva Visual Leveler
Save
Projects
Search by project name
All Projects
by
risk
Select All
Select None
Shaw St - Pipe Replacement 15
Upgrade Avondale Station Elec... 14.25
Project209 13.5
Project150 12.375
Project148 11.85
Project151 11.461
Project172 11.408
Project196 11.325
Project163 11.092
Project177 11.039
Project161 10.933
Project185 10.933
Project200 10.425
Project156 10.353
Project141 10.35
Project165 10.3
Project179 10.275
Cost
25M
20M
15M
10M
5.0M
0.0
2016
2017
2018
2019
2020
Exclude
Labour
60k
50k
40k
30k
20k
10k
0.0
Total Risk
800
1.00k
1.20k
1.40k
746.657
Optimizer
Algorithm
Global Search
Solving Time
1000
ms
RUN
Undo
Redo


Risk Return on Investment
Optimizer results using RROI
as the primary constraint.
Net Capital
$4,000,000
$3,500,000
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
0%
50%
100%
150%
200%
250%
300%
RROI (%)
$118M
$138M
$147M
$156M
Defer

Validation

Are we on the right path?

External Standards & Best Practices

- ISO 55000, PAS 55, ISO 31000 & Risk Management best practices
- Worldwide asset management & regulatory developments
- OEB decisions & future direction

Independent 3rd Party Assistance & Review

- Asset Investment Planning tools – RIVA via RFP in 2015
- Asset Health Review – UMS via RFP in 2015
- Asset Health Review Assurance – via RFP fall 2016
- Asset Management System Benchmarking/ISO 55000 – via RFP fall 2016
  - Initial report with gap analysis
  - Final report in time for our next rate case filing

Goal is to produce a multi year Asset Plan

Closing Remarks

Andrew Mandyam
Kevin Culbert

2015-2016 Gas Supply Plan Memorandum

Enbridge Gas Distribution Inc.

April 2016

Witnesses: D. Small, A. Welburn

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.*

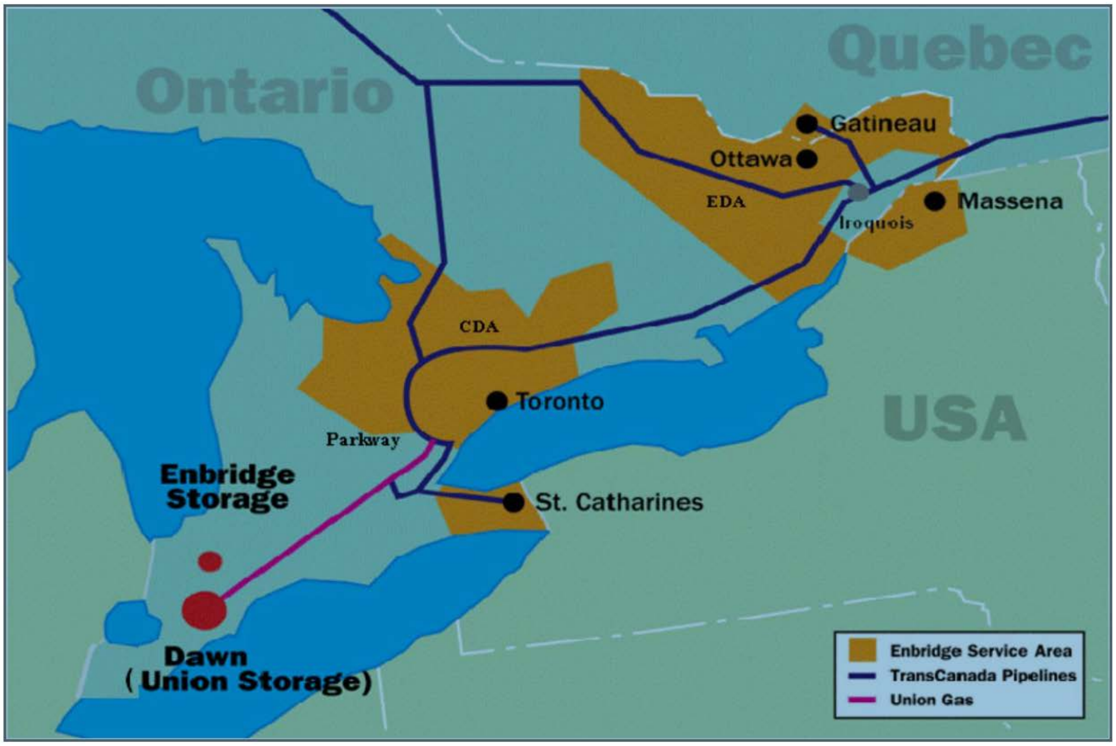
This document has been prepared in response to the reporting requirement for a Gas Supply Plan Memorandum as determined in the Board's Decision.

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 over 30,000 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, Gatineau 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



The Enbridge System is divided into two distinct regions for gas supply planning purposes. The Eastern Delivery Area ("EDA") and Central Delivery Area ("CDA") are identified in Figure 1. The EDA contains Ottawa and the surrounding area, while the CDA contains the GTA region, as well as St. Catharines and the surrounding area.

Enbridge customers have the option to choose between multiple service types with varying degrees of sophistication:

- Sales Service – customers rely on the Company to provide gas supply, transportation, and load balancing services;
- Western Transportation Service ("WTS") – customers deliver gas supply to the Empress Hub in Alberta and rely on the Company to provide transportation and load balancing services;
- Ontario Transportation Service ("OTS") – customers deliver gas supply to the Enbridge franchise area and rely on the Company to provide load balancing services;
- Dawn Transportation Service ("DTS") – customers deliver gas supply to the Dawn Hub in southwestern Ontario and rely on the Company to provide transportation and load balancing services;[2]
- Unbundled Service – customers do not require gas supply, transportation, or load balancing services from Enbridge, and are not considered in the gas supply plan.

[2] This description is specific to Phase 2 of DTS. Refer to Section 3.2 for details on both phases of the service

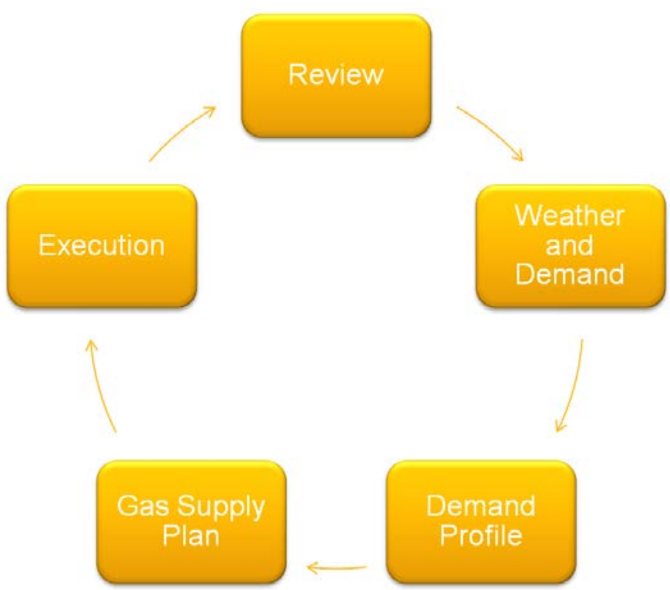
Under the service types listed above, Enbridge offers several rate classes which vary to suit its customers' different volume and load factor requirements. Two of the Company's rate classes feature interruptible service, whereby customers may be required to curtail their natural gas consumption at the request of Enbridge. These interruptible customers are a critical component to the system and provide a necessary advantage to the rest of the Company's customers through the optimal operation of the distribution network.

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 near 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 sales service and bundled transportation customers throughout the calendar year. The Company's gas supply portfolio is structured to meet peak day demand (i.e. the day of highest demand), baseload demand, as well as seasonal demand throughout the winter and summer months. The gas supply planning process is conducted annually, and the resulting gas supply plan is filed with the Board as part of the Company's annual rate adjustment application. Establishment and execution of the gas supply plan is summarized in Figure 2 as a cycle of phases.

Figure 2: Gas Supply Planning Cycle

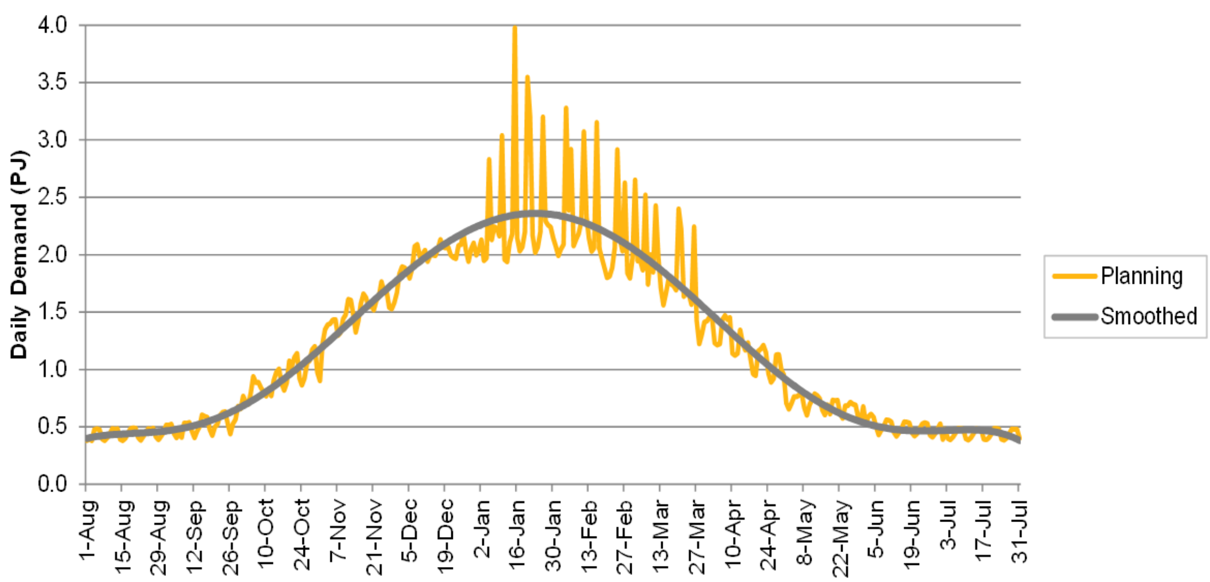


The cycle begins with a review of recent and expected future market conditions. The North American natural gas market is evolving at a very rapid pace. Natural gas production from shale formations has created new procurement opportunities and led to the development of new and repurposed transportation 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 greater than production in the Western Canadian Sedimentary Basin ("WCSB").

The annual demand budget is developed in the weather and demand phase. As per Board approved methodologies, the Company's Economics & Business Performance department forecasts annual demand using projected degree days, customer additions, information from large volume customers and other economic variables. The annual demand budget is provided to the Company's Energy Supply and Policy department, where development of the gas supply plan for the upcoming test year can begin.

In the demand profile phase, Board approved Design Criteria[3] is used to distribute the annual demand budget into a daily demand profile. The Design Criteria considers seasonal weather patterns as well as peak day demand and near-peak demand conditions (also 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 are 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.

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

[3] 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.

demand resulting in reduce pricing volatility experience on customer bills. 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* – As the "supplier of last resort", Enbridge mitigates delivery interruption by sourcing supplies from established liquid hubs and transporting to the Enbridge franchise area on firm transportation contracts;
- *Diversity* – Enbridge 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* – The Company manages shifting demand requirements through differentiated supply procurement patterns and provides operational flexibility through service attributes and contract parameters; and
- *Landed Cost* – Enbridge balances gas supply costs with the other principles and ensures low cost natural gas supply for customers.

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

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 to manage Unabsorbed Demand Charges ("UDC"). Outcomes from these meetings are incorporated into the operational planning meetings.

The operational planning meetings are overseen 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 and 2015 Natural Gas Market Reviews

The 2014 Natural Gas Market Review[4] 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.

For the 2015 Natural Gas Market Review[5], the broad discussion of the North American natural gas market was reengaged, but Enbridge also provided thoughts on two additional issues:

1) Ontario's evolving climate strategy, including its Cap and Trade legislation, and
2) Natural gas community expansion.

These issues could impact how natural gas is procured and how Enbridge serves its customers.

Beginning in 2017, Enbridge will be required to purchase allowances to account for the CO_2 emissions associated with its customers' consumption of natural gas. This will effectively increase the cost of consuming gas since the cost of allowances purchased by Enbridge will be passed on to customers. Depending on the price of allowances, which will vary from quarter-to-quarter, the increase in cost could lead to a reduction in consumption volume. In the longer term, the Company could explore alternative sources of supply, such as Renewable Natural Gas, which will impact the gas supply planning process.

[4] 2014 Natural Gas Market Review (EB-2014-0289) documentation is located on the Board website at http://www.ontarioenergyboard.ca/oeb/Industry/
[5] 2015 Natural Gas Market Review (EB-2015-0237) documentation is located on the Board website

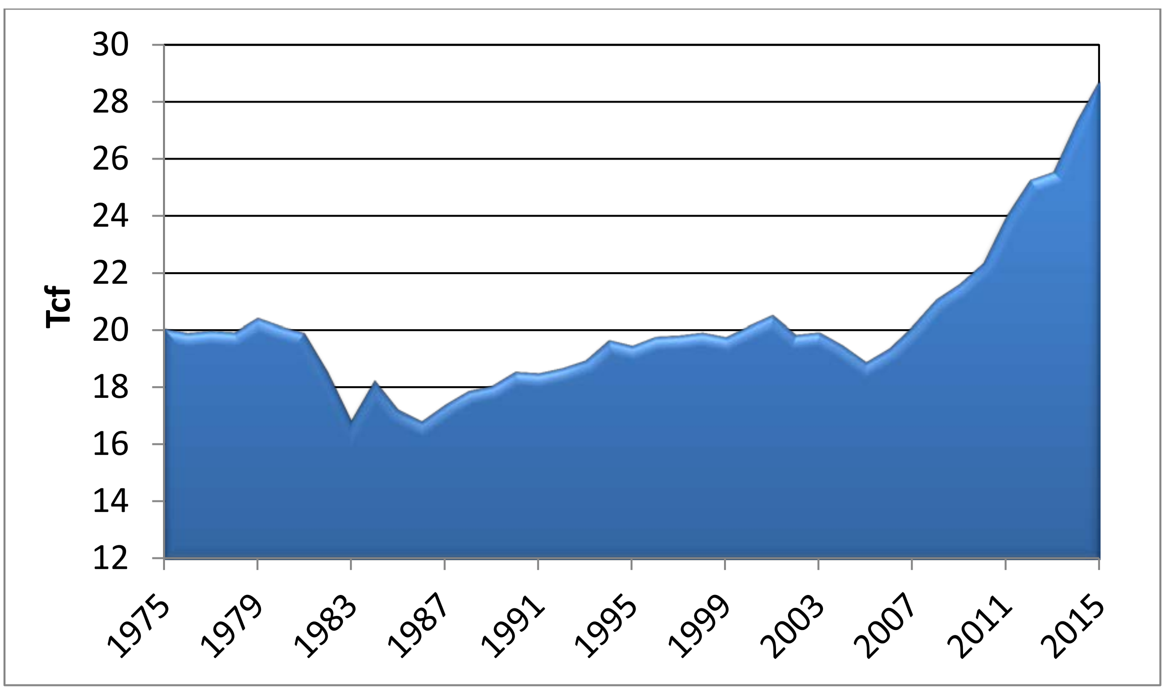
2.2 United States Natural Gas Supply

Technological advances in horizontal drilling and hydraulic fracturing have facilitated the economical extraction of natural gas from shale deposits, transforming the North American natural gas industry in the process. 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 as demonstrated in Figure 5.

Natural gas supply from shale has been the sole driver of United States natural gas production. In the past decade, production from United States shale resources has grown exponentially while non-shale production in the US and Canada has declined, as shown in Figure 6.

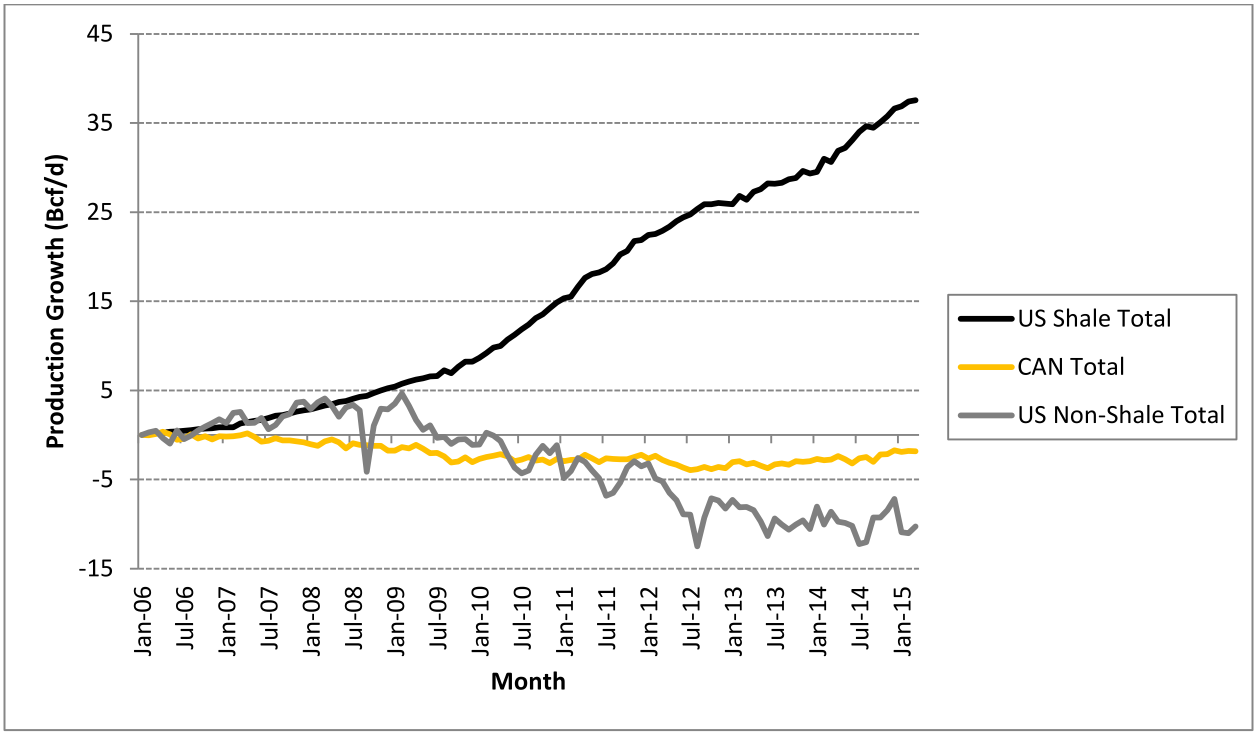
The increase in natural gas production from shale basins has resulted in declines in natural gas prices. The steep increase in natural gas prices experienced at the turn of the century reversed as natural gas production from shale basins expanded. This contributed to a significant decrease in natural gas prices in 2009 and prices have been trending downward since that time as indicated in Figure 7.

Figure 5: United States Natural Gas Production History



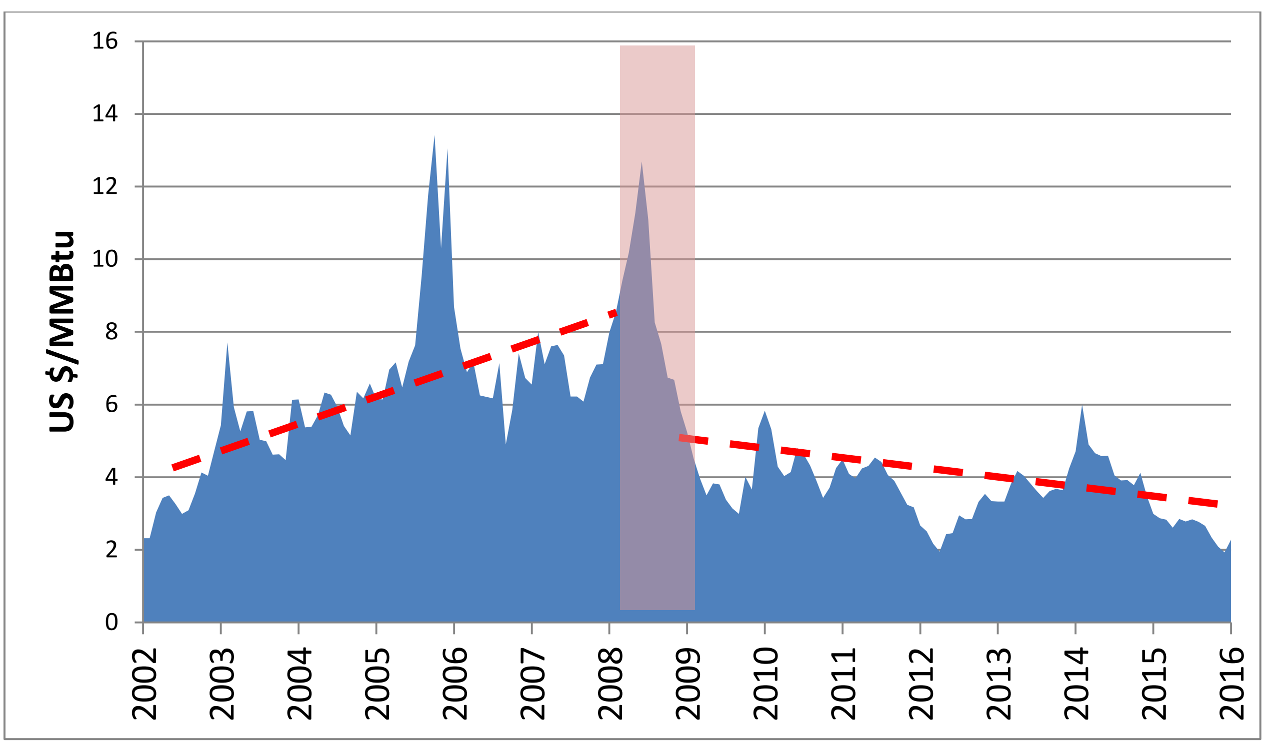
Source: EIA

Figure 6: Production Growth from Shale vs. Non-Shale



Source: EIA & NEB

Figure 7: Henry Hub Price History



Source: EIA & Navigant

The location of shale supply basins has had a significant impact. Historically, gas demand had 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 8, 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 transportation costs if these supplies can be accessed. This has led to the reconfiguration of the North American natural gas grid and flows. Some 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 8: North American Shale Gas Basins

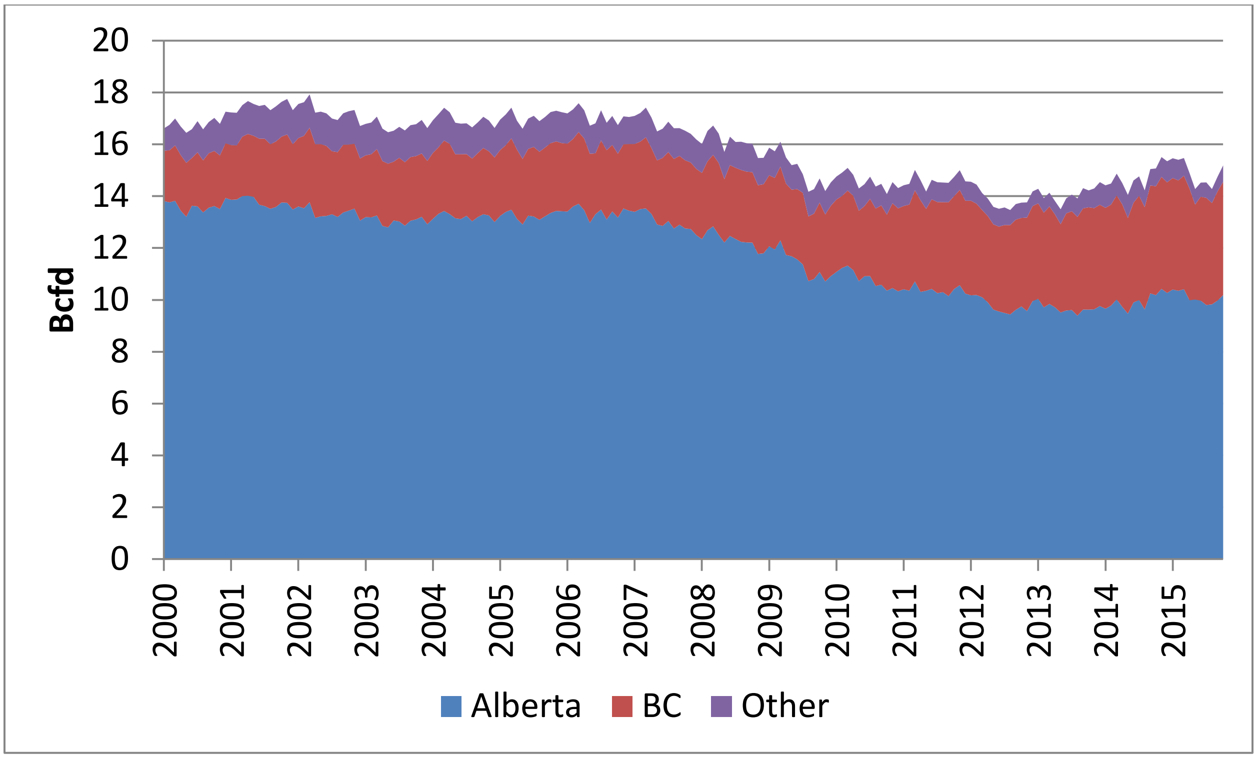
Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

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 its portfolio diversity by contracting on Alliance Pipeline and Vector Pipeline which provided additional access to WCSB supply and Chicago supply.

As shown in Figure 9, production in the WCSB peaked in 2001 and steadily decreased between 2001 and 2013. The post-2013 increase in WCSB production is the result of recent evaluations of unconventional gas potential in the region, such as the Motney, Horn River, and Liard basins.

Figure 9: Historical Canadian Natural Gas Production



Source: NEB

3. OEB 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 involve 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 serve as an important step in providing similar incremental market access to eastern Ontario, Québec, 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.[6]

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 in November 2014.

With the GTA and Parkway projects, along with other necessary facilities such as the King's North project, not due for completion until 2016, the first phase of the Dawn Access Settlement required eligible customers to take assignment of a portion of the Company's TransCanada Dawn to CDA short haul capacity to ensure delivery to the franchise area. Upon completion of the additional necessary facilities such as the Vaughan Mainline project, preconditions for the second phase of the Dawn Access Settlement will be met and the assignment of capacity will no longer be necessary. Those preconditions are as follows:

a) Downstream Infrastructure must be in service;
b) Enbridge must have acquired the natural gas transportation services from Union Gas, or TransCanada, or both, that Enbridge needs in order to implement a bundled DTS;
c) Enbridge must have completed system changes to EnTRAC, CIS and Open Link required to accommodate DTS and other future transportation services; and
d) Enbridge must have received approval of the Board for recovery from customers of the costs of implementing DTS, including particularly the costs of required system changes.

Details of the assignment are discussed further in Section 5 of this memorandum.

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

3.3 2014 April and October QRAMs

The level of demand experienced over the winter of 2013/2014 was significantly higher than budgeted. This led to low storage balances late in the winter season and the need to procure incremental supply from the spot market. The increased demand 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[7] 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 the Company to propose changes to the management of storage balances. These proposed changes were filed in Enbridge's 2015 Rate application and are discussed below.

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 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 Board approved the proposed changes for the 2015 gas supply plan, allowing the Company to maintain full deliverability from storage until the end of February and maintain sufficient storage deliverability throughout March such that a March peak day could be met as late as March 31st. Enbridge has continued operating under these more conservative storage targets in the 2016 gas year, and intends to maintain this gas supply plan in subsequent years.

4. NEB 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 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 the decision, stating "*[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*"[8].

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 was given greater discretion in setting the bid floors for services such as Interruptible Transportation ("IT") and Short Term Firm Transportation

[7] EB-2014-0191 Decision and Order dated September 25, 2014, page 4.
[8] RH-003-2011 Reasons for Decision, dated March 2013, page 1.

("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 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. However, 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 uncontracted long-haul FT capacity into eastern Ontario and Québec 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 the Company'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.

4.4 Abandonment Set Aside and Collection Mechanisms

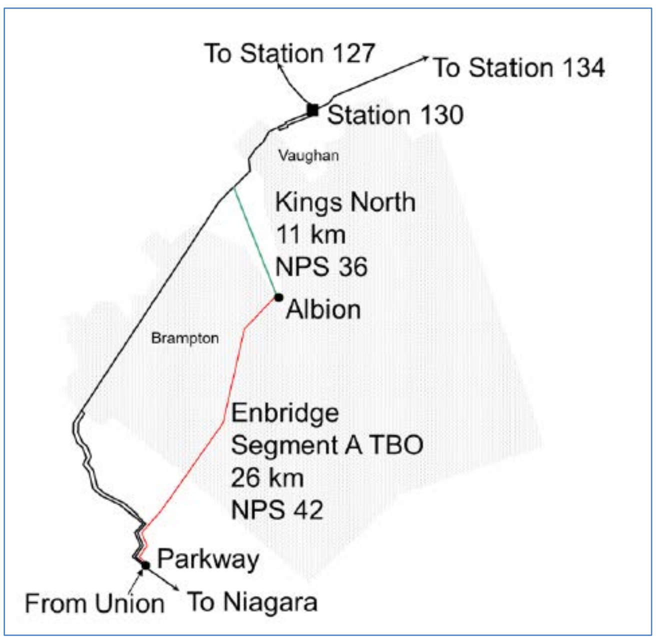
The NEB initiated the Land Matters Consultative Initiative ("LMCI") in January 2008 for the purpose of ensuring that funds are available when abandonment costs are incurred for all pipelines regulated by the NEB. An Abandonment Surcharge is now applied to all paths on the TransCanada Mainline resulting in increases in 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*"[9]. 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.

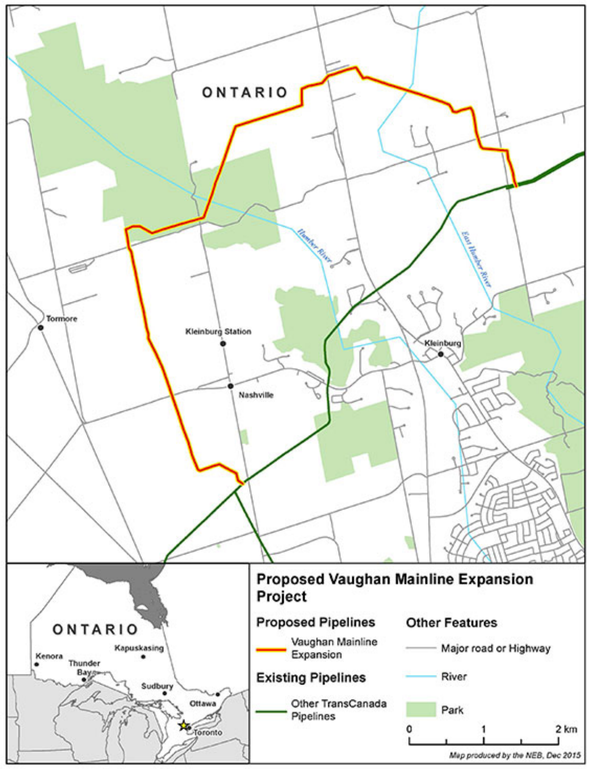
As a result of the Mainline 2013-2030 Settlement, TransCanada agreed to address the capacity restrictions on the Mainline between Parkway and the Maple compressor station (Station 130) by contracting for transportation by others ("TBO") capacity on Segment A of Enbridge's GTA Project and constructing new infrastructure such as The King's North project and the proposed Vaughan Mainline Project. The King's North Project is illustrated in Figure 10 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. The Vaughan Mainline Project is illustrated in Figure 11 and will consist of approximately 11.7 km of new natural gas pipeline which will connect into the King's North Project and the existing TransCanada Line 200-2. Through coordinated open seasons on the TransCanada Mainline and Union Gas transmission system, market participants now have the opportunity to procure incremental natural gas supply at Dawn for transportation to eastern Ontario, Québec and the northeast region of the United States.

Figure 10: King's North Project[10]



[9] RH-001-2014 TransCanada Pipeline Limited Application for Approval of Mainline 2013-2030 Settlement, page 1.
[10] TransCanada King's North Connection Pipeline Project application dated August 2014, Page 3-9

Figure 11: Vaughan Mainline Project[11]



Market access to incremental FT from Dawn addresses the reliability concerns related to the lack of renewal rights inherent 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.

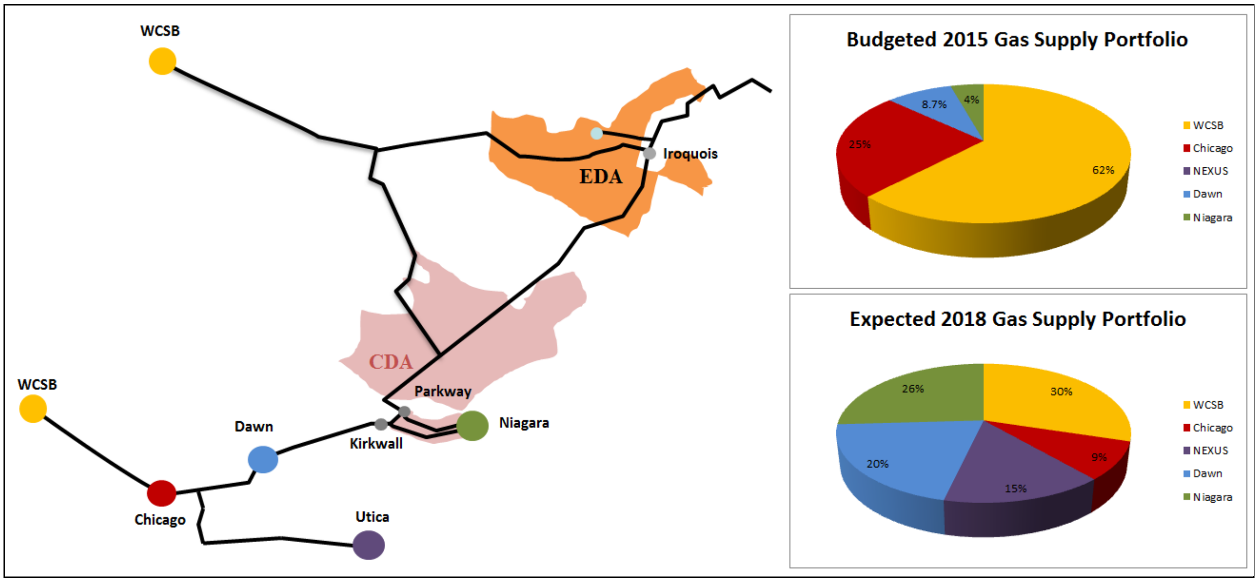
The replacement of FT-NR capacity with FT capacity from Dawn is a critical improvement to the reliability of Enbridge's gas supply plan. The open seasons offered by TransCanada and Union Gas for the incremental FT capacity required a 15 year term commitment. The 15 year term will be managed through flexibility 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 subsequent to the Mainline 2013-2030 Settlement, Enbridge is expecting to more evenly distribute the amount of supply that is procured for customers supplied by Enbridge from various supply hubs across North America, as shown in Figure 12. This diversity reduces significant reliance on any one supply basin, increases reliability and lowers the landed cost of gas supply into the

[11] Section 58 Application for the Vaughan Mainline Expansion Project, November 2015, Appendix 1-1

franchise. This is accomplished by replacing more expensive long haul transportation with short haul transportation as discussed in the GTA and Parkway Projects section of this memorandum.

Figure 12: Supply Portfolio Diversification



The increased diversity has most notably resulted in a shift in supply procurement between the WCSB and Dawn. In order to mitigate any impacts that such shifts will have on these supply hubs, Enbridge will continue to evaluate opportunities to diversify its portfolio. One of the most recent examples of this includes the Board pre-approval to contract for capacity on the NEXUS Pipeline as discussed in more detail later in this document.

4.6 Storage Transportation Service ("STS") Modernization and Standardization Application

On February 18, 2016, TransCanada filed an application for STS Modernization and Standardization, seeking approval of amendments to the existing STS tariff. STS is an important part of a portfolio of services that Enbridge relies upon to serve its more than two million customers. In its 2016 portfolio, Enbridge is contracted for 80,611 GJ/d of STS capacity in the EDA, and 283,892 GJ/d in the CDA[12].

On April 6, 2016, the National Energy Board announced they would hold an oral public hearing to consider the merits of TransCanada's application. Enbridge will observe the hearing process and participate to the extent required to see the needs of its customers properly addressed.

[12] These contracts can be identified in Appendix 8.5, Lines 12-14

5. 2016 Gas Supply Plan

5.1 Peak Day Coverage

A discussion on peak day coverage was provided in EB-2015-0114, 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-2015-0114, Exhibit D1, Tab 2, Schedule 6 is provided in Appendix 8.4.

> *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 in EB-2011-0354 at Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2016 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak in the Enbridge CDA and 48.2 degree days in the Enbridge EDA. Enbridge is forecasting a design peak day level of 106,363 10^3m^3 (3.9 PJs) during the winter season of the 2016 fiscal year.*
>
> *The completion of the GTA Project enables the Company to make a number of changes in the Enbridge CDA. The primary change that occurs is an increase in the contracted M12 capacity for transport between Dawn and Parkway that the Company has with Union Gas. This amounts to an increase in Union M12 capacity of 400,000 GJs per day. Coinciding with the increase in available transport from Union Gas, the Company was able to de-contract 266,000 GJs per day of long haul TCPL capacity from Empress to the Enbridge CDA. The Company also contracted for 200,000 GJs per day of incremental short haul capacity on TCPL from Niagara to the Enbridge CDA/Parkway. To facilitate Direct Purchase customers to begin delivering their daily supplies to Dawn, the Company will be assigning to them a portion of the Company's contracted TCPL Dawn to CDA capacity. This will be a two year assignment from November 1, 2015 to October 31, 2017 and was agreed to by parties in the Dawn Access Consultative (EB-2014-0323) and identified as Phase 1. The Company has another short haul contract with TCPL for capacity from Dawn to Iroquois. In previous years, the Company assumed utilization of this capacity for purposes of meeting its peak day requirements in the Enbridge CDA. With incremental transport on Union Gas available in 2016, the Company intends to use this capacity for purposes of meeting peak day demand in the Enbridge EDA for 2016. Finally, the completion of the GTA Project will enable the Company to avoid acquiring costly peaking supplies in the CDA in 2016.*
>
> *Management of peak day demand in the Enbridge EDA undergoes minor changes as well. While the Company continues to rely heavily on long haul capacity on TCPL to meet its peak day requirements, the shift of the above mentioned Dawn to Iroquois capacity to meet EDA peak day demand will allow the Company to reduce its need for Peaking Service in the Enbridge EDA.*
>
> *Despite the reduction of contracted long haul TCPL capacity discussed above, the Company is forecasting that it will be unable to fully utilize its contracted long haul TCPL capacity in 2016. The Company is forecasting that there will be 7.6 PJs of Unutilized Capacity ("UDC") in 2016 at a forecast cost of $15.7 million. This forecast is based upon the TCPL tolls, inclusive of*

> *abandonment surcharges, in place at the time of the derivation of the July 2015 QRAM. Consistent with 2015, the Company is proposing that any actual UDC costs incurred during the year would be captured in a 2016 Unabsorbed Demand Charges Deferral Account ("2016 UDCDA"). In 2016, Enbridge will use best efforts to mitigate UDC that would otherwise be recorded in the 2016 UDCDA. For example, during the summer months when Enbridge is injecting gas into storage, whenever possible, the Company will use transportation capacity to displace discretionary purchases of gas at Dawn. If unutilized capacity still remains, the Company will use best efforts to make that capacity available to third parties to mitigate the UDC costs.*
>
> *In the EB-2014-0276 Settlement Agreement, the Company committed to providing a draft of any necessary UDC mitigation plan, similar to the one agreed to in 2015, as a part of its supply plan. The draft mitigation plan for 2016 is shown at Exhibit D1, Tab 2, Schedule 1, Appendix A. Also within the Settlement Agreement reached in 2015, the Company committed to providing an update to the aforementioned mitigation plan near the end of the winter season of the year in question based upon any changes in information. Similar to 2015, the Company intends to continue to provide monthly reporting of the on-going amounts in the 2016 UDCDA as well as an update to its 2016 UDC mitigation plan with the March 2016 report. The Company has provided at Appendix A, a monthly breakdown of the forecasted 2016 UDCDA.*

The Company, as per the Settlement Agreement mentioned above, has updated its 2016 UDC mitigation plan. Provided at Appendix 8.7 is a copy of the updated monthly breakdown of the forecasted 2016 UDCDA that the Company reported at the end of March 2016 which now indicates zero UDC in 2016.

5.2 Transportation

A discussion on the transportation assets that were included in the 2016 Gas Supply Plan was provided in EB-2015-0114, 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-2015-0114, Exhibit D1, Tab 2, Schedule 2 is provided in Appendix 8.5.

> *Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada and in the United States during the 2016 Fiscal Year. These include service entitlements with TCPL (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 fiscal year these contacts were deemed to expire. For instance, the Company has chosen not to renew its contract 75,000 mcf/day 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. The Company has included the acquisition of 200,000 GJ/day of Niagara Falls to Enbridge Parkway CDA capacity on TCPL.*

> *For the purposes of the 2016 forecast, the Company has assumed the assignment of 122,978 Gj/day of TCPL short haul capacity to Direct Purchase customers effective November 1, 2015 to October 31, 2017 in accordance with Phase 1 of the Dawn Access Consultative (EB-2014-0323).*
>
> *M12 and M12X service entitlements on the Union system currently total 2,225,102 GJ/day (2,081 MMcf/day) and will increase by 400,000 GJ/day (375 Mmcf/day) upon completion of the GTA Project. Enbridge also holds 236,000 GJ/day of westerly C1 transport on the Union system. 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 use of the Chatham "D" Storage pool. The gas cost forecast assumed January 1, 2015 Union tolls. A copy 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 2016 Gas Supply Plan was provided in EB-2015-0114, Exhibit D1, Tab 2, Schedule 1 as part of the annual rate filing and an excerpt is included below. The list of storage contracts from EB-2015-0114, Exhibit D1, Tab 2, Schedule 2 is provided in Appendix 8.6.

> *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. A summary of Storage contracts has been provided at Exhibit D1, Tab 2, Schedule 2, Page 2. For purposes of the 2016 gas cost forecast, the Company has assumed the amount and value of existing third party storage contracts 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 2016 Storage & Transportation Deferral Account (2016 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.

In 2015 the Company implemented a change with respect to how it planned to manage its storage balances and has assumed a similar practice for purposes of developing its 2016 gas supply plan. The Company is forecasting storage targets such that maximum deliverability from storage can be maintained until the end of February and that deliverability from storage is sufficient to meet March peak day demand as late as March 31.

Also during the April 2014 and October 2014 QRAM proceedings the Company explained its utilization of a seven day ahead forecast of degree days demand along with budgeted weather beyond seven days to make gas procurement decisions. Starting in 2015, the Company made a change in how it used forecasted weather demand to make procurement decisions. For 2016, 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. In addition, the Company will continue to utilize medium term weather forecasts as a means of assessing medium term demand impacts. These forecasts will be used to decide whether or not it should adjust its supply plan for the upcoming month or the remainder of the winter season.

Maintaining higher storage balances later into the winter season in conjunction with using a medium term weather forecast will allow the Company to make adjustments to the supply plan to meet changing demand. This 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, Québec, 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, Québec, 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 the earlier of November 1, 2017 or the date of commencement of a 170,000 GJ per day short-haul contract from Union Parkway Belt to Enbridge EDA. Enbridge has also executed precedent agreements with Union Gas for 170,000 GJ per day from Dawn to Parkway, effective November 1, 2016.

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 if the Parties to the Settlement Agreement determined that an Acceptable Approval of the Mainline 2013-2030 Settlement Agreement had not been obtained once the Reasons for Decision were made available by the NEB. In conjunction with the 2017 NCOS, Union Gas conducted an open season on their transmission system.

Enbridge has executed precedent agreements with TransCanada to convert existing long haul contracts to short haul contracts 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. Addressing 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.

6.4 2018 Open Seasons

Enbridge did not bid into TransCanada or Union Gas Open Seasons for capacity available effective November 1, 2018. In order to meet any forecasted 2019 design day supply deficiency, the Company will procure a combination of incremental delivered supply or peaking services. The procurement process will be conducted closer to 2018 to properly take into account any franchise or market developments.

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"[13] which the Board indicated would be conducted through a stakeholder consultation. Such an examination took place in the EB-2015-0238 proceeding, where the gas supply planning processes of Enbridge and Union Gas were discussed and compared, with focus on issues such as guiding principles, design day planning, utilization of storage, and market based solutions. Stakeholder sessions for this proceeding have concluded but Board Staff has not yet issued its recommendations.

7.2 Incremental Storage

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

As discussed earlier in this memorandum, Enbridge incorporated changes in how it manages storage deliverability targets in its 2015 and 2016 gas supply plans, by increasing forecasted natural gas supply purchases in the winter period and subsequently decreasing forecasted natural gas supply purchases in the summer period. 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.

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 13.

Figure 13: Incremental Storage Analysis Summary

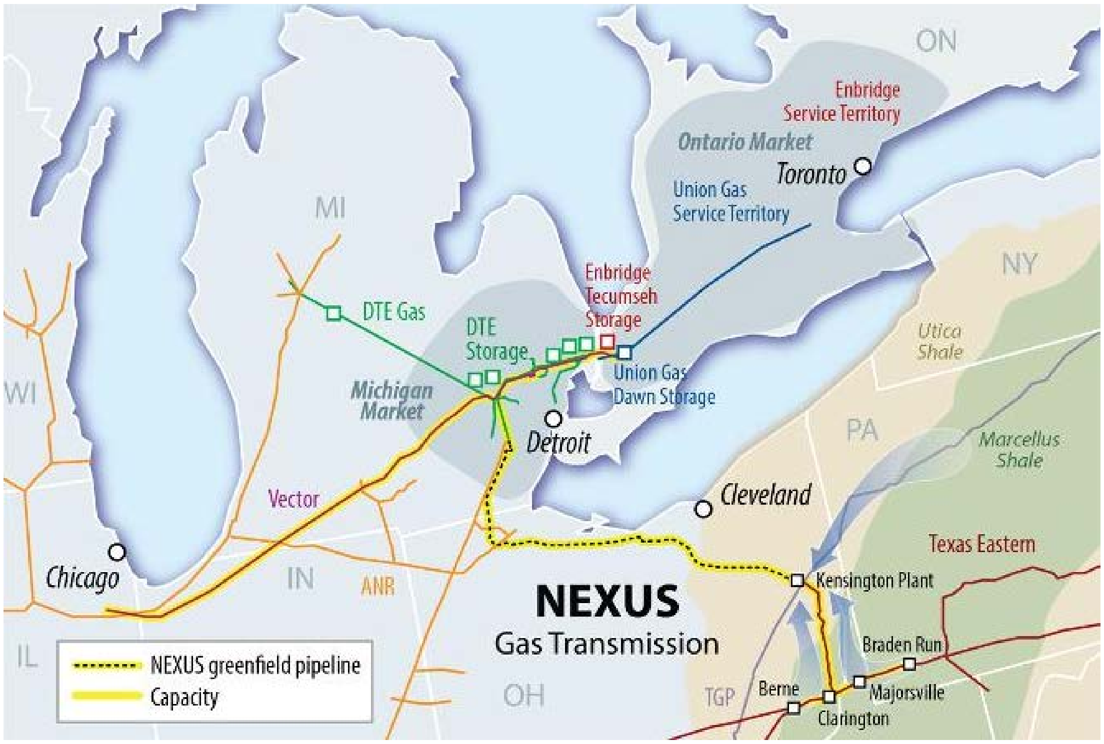
Incremental Storage Requirements*: Various Design Criteria (Normal Distribution)			
Design Criteria Recurrence Interval	Associated Probability of Being ≥	Central Weather Zone Winter HDD	Incremental Storage Requirement (Bcf)
Current 1 in 2	50%	2,945	-
1 in 5	20%	3,207	9
1 in 10	10%	3,303	14
1 in 15	≈6%	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 14.

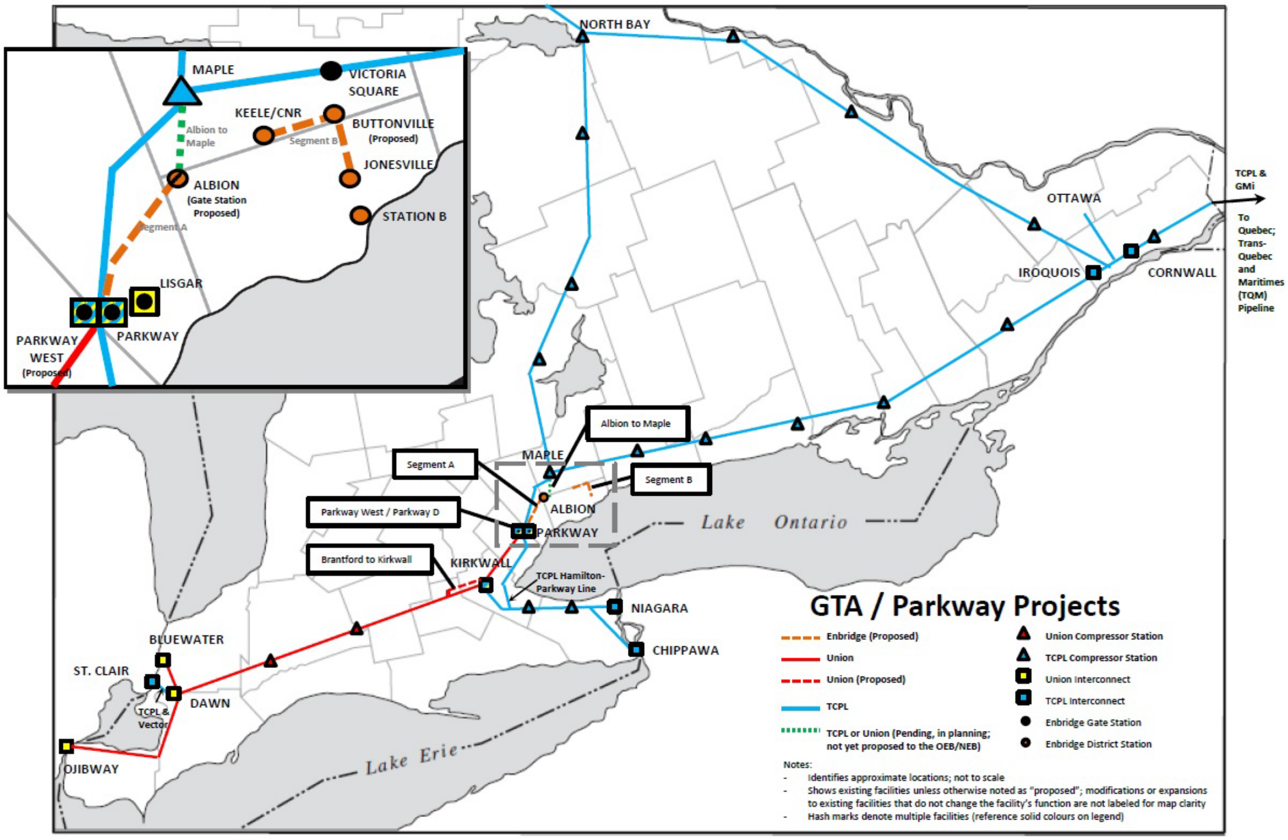
Figure 14: NEXUS Gas Transmission



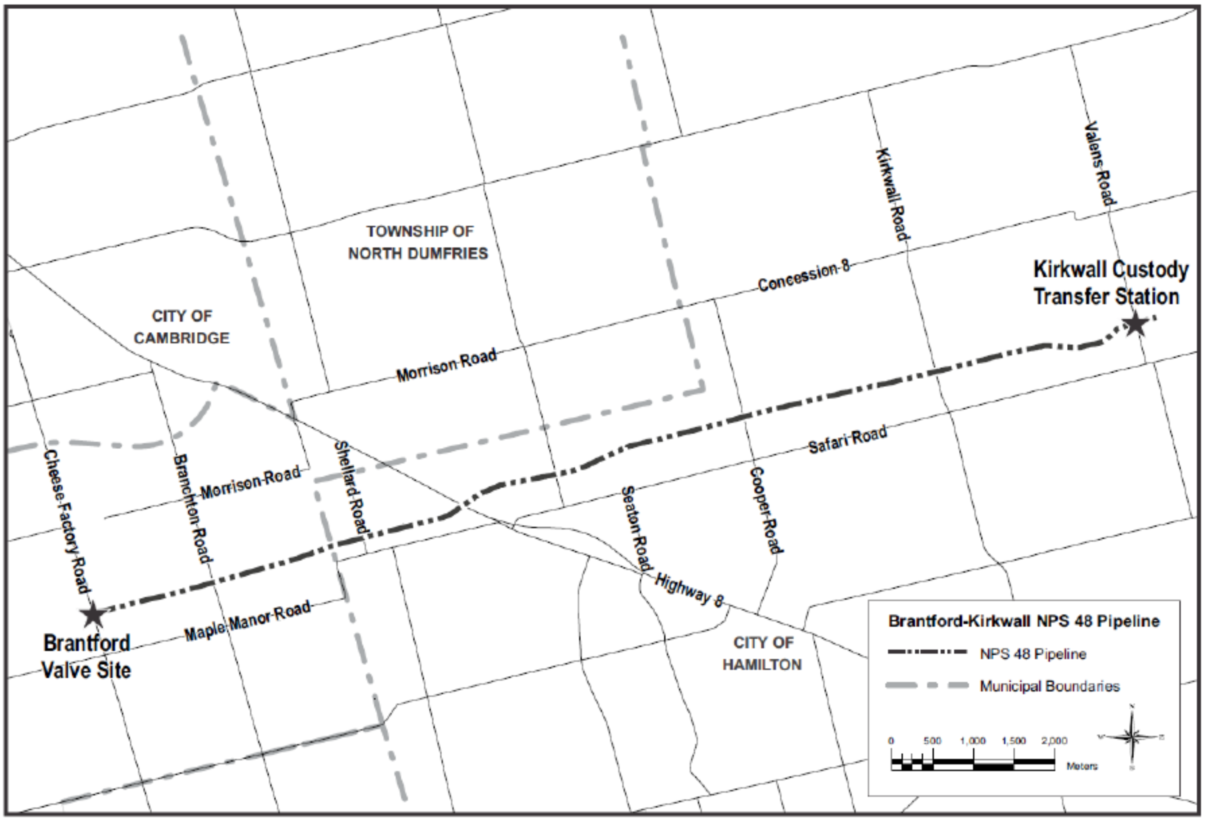
Enbridge signed a precedent agreement with NEXUS for 110,000 Dth per day for firm transportation service commencing on November 1, 2017 to diversify its gas supply plan portfolio while improving the reliability of supplies being transported to Dawn at a competitive landed cost. In EB-2015-0175, the Board granted Enbridge pre-approval for the cost consequences of its long-term transportation contract for NEXUS capacity.

8. Appendices

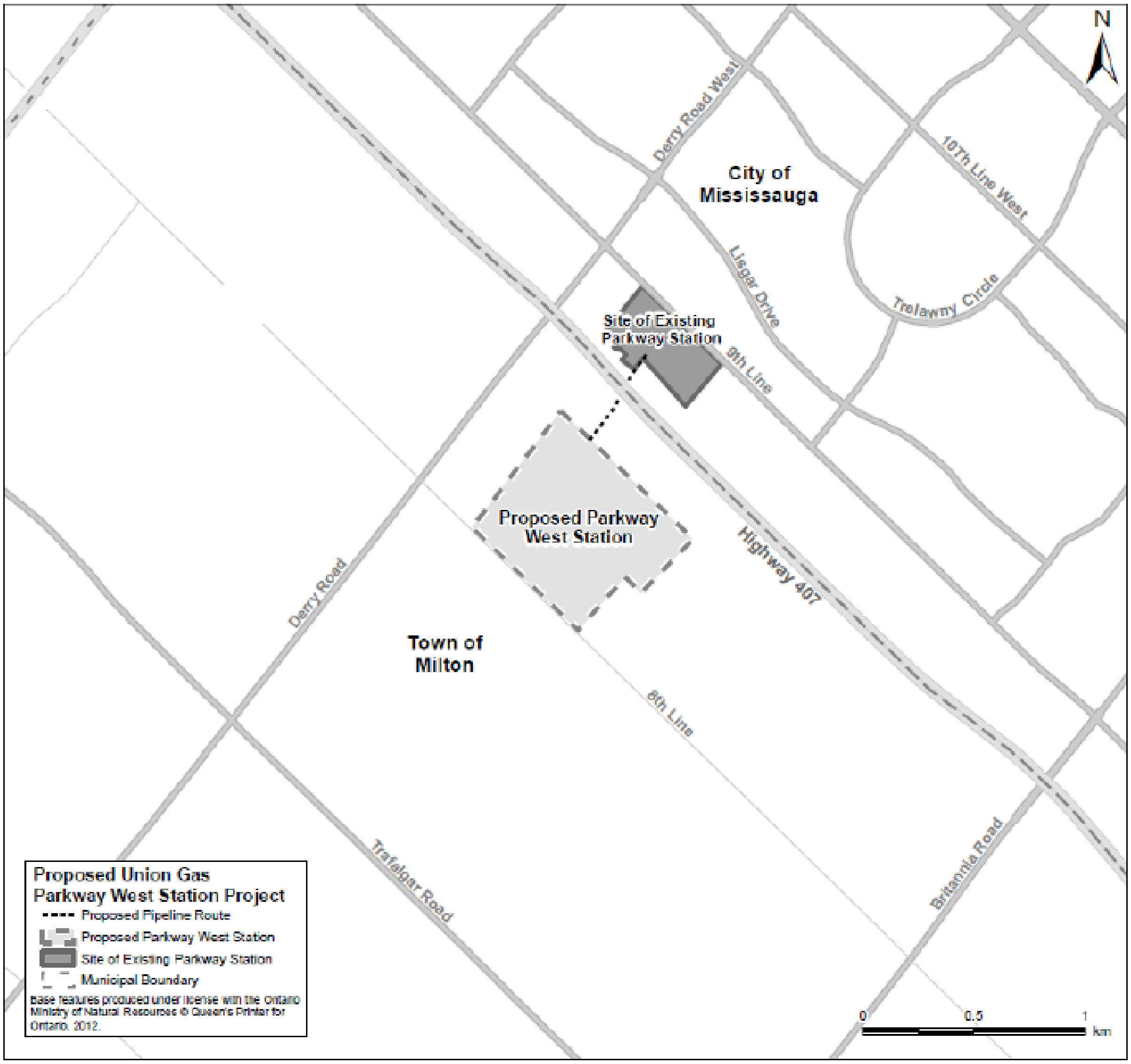
8.1 GTA Project Map



8.2 Brantford-Kirkwall/Parkway D Project



8.3 Parkway West Project Map



8.4 2016 Budget Peak Day Demand

Filed: 2015-09-28
EB-2015-0114
Exhibit D1
Tab 2
Schedule 6
Page 1 of 1

	2015 Budget Peak Day Demand	Column 1	Column 2	Column 3	2016 Budget Peak Day Demand	Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,303,548	674,042	3,977,590	Demand	3,321,901	686,930	4,008,832
2.	Less Curtailment	(83,874)	(33,259)	(117,133)	Less Curtailment	(87,208)	(36,056)	(123,263)
3.	Net Peak Day Demand	3,219,674	640,783	3,860,457	Net Peak Day Demand	3,234,694	650,875	3,885,568
4.	TCPL FT Capacity	404,538	390,627	795,165	TCPL FT Capacity	138,468	390,377	528,845
5.	TCPL STFT	-	-	-	TCPL STFT	-	-	-
6.	TCPL Short Haul	158,720	114,000	272,720	TCPL Short Haul	226,840	154,000	380,841
7.	TCPL STS	369,465	80,611	450,076	TCPL STS	369,465	80,611	450,076
8.	Ontario T-Service	243,353	5,718	249,071	Ontario T-Service	231,114	5,417	236,531
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	2,175,027	-	2,175,027
10.	Delivered Service	167,739	-	167,739	Delivered Service	132,738	-	132,738
11.	Peaking Service	105,506	52,754	158,260	Peaking Service	-	20,469	20,469
12.	Total Supply	3,224,348	643,710	3,868,058	Total Supply	3,273,653	650,875	3,924,527
13.	Sufficency/(Deficiency)	4,674	2,927	7,601	Sufficency/(Deficiency)	38,959	-	38,959

8.5 Transportation Contract Summary

Filed: 2015-09-28
EB-2015-0114
Exhibit D1
Tab 2
Schedule 2
Page 1 of 2

Status of Transportation & Storage Contracts

Item #	Transportation Summary	Route	Total Contracted Daily Volume		Fuel Rate	Monthly Demand Charge		Expiry Date	
	Current Contracts								
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	60.77142	$/GJ	31-Oct-17	[1]
2	TCPL FT - CDA	Empress to CDA	75,000	GJ	varies	60.77142	$/GJ	31-Oct-18	
3	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	62.50257	$/GJ	31-Oct-22	[2]
4	TCPL FT - EDA	Empress to EDA	166,000	GJ	varies	62.50257	$/GJ	31-Oct-17	[3]
5	TCPL FT - Iroquois	Empress to Iroquois	26,956	GJ	varies	63.11183	$/GJ	31-Oct-22	
6	TCPL FT Dawn to CDA		149,818	GJ	varies	11.40236	$/GJ	31-Oct-22	
7	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(122,978)	GJ	varies	11.40236	$/GJ	31-Oct-17	[4]
8	TCPL FT Dawn to EDA		114,000	GJ	varies	21.33019	$/GJ	31-Oct-22	
9	TCPL FT Dawn to Iroquois		40,000	GJ	varies	20.49473	$/GJ	31-Oct-22	
10	TCPL FT Parkway to CDA		572	GJ	varies	6.29836	$/GJ	31-Oct-22	
11	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	6.14977	$/GJ	31-Oct-22	
12	TCPL STS Parkway to CDA		283,892	GJ	varies	5.92119	$/GJ	31-Oct-22	
13	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	15.60578	$/GJ	31-Oct-22	
14	TCPL STS Parkway to EDA		9,716	GJ	varies	15.60578	$/GJ	31-Oct-22	
15	TCPL FT Parkway to EDA		170,000		varies	15.60578	$/GJ	31-Oct-31	[5]
16	Niagara to CDA		200,000	GJ	varies	8.35336	$/GJ	31-Oct-30	
17	Nova Transmission	AECO to Empress	166,869	GJ	N/A	5.65300	$/GJ	31-Oct-16	
18	Alliance Transportation		25,000	mcf	N/A	N/A		31-Oct-16	[6]
19	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	30-Nov-17	
20		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	30-Nov-17	
21	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	30-Nov-17	
22		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	30-Nov-17	
23	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.6040	$/GJ	31-Oct-22	
24	Union Gas Dawn to Parkway		106,000	GJ	varies	2.6040	$/GJ	31-Oct-18	
25	Union Gas Dawn to Parkway		57,100	GJ	varies	2.6040	$/GJ	31-Oct-19	
26	Union Gas Dawn to Parkway		18,703	GJ	varies	2.6040	$/GJ	31-Oct-17	
27	Union Gas Dawn to Parkway - M12X		200,000	GJ	varies	3.2440	$/GJ	31-Oct-22	
28	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.6040	$/GJ	31-Oct-17	
29	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.1930	$/GJ	31-Oct-17	
30	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.1930	$/GJ	31-Oct-17	
31	Union Gas Parkway to Dawn - C1		236,586	GJ	varies	0.6400	$/GJ	31-Mar-17	
32	Union Gas Dawn to Parkway		400,000	GJ	varies	2.6040	$/GJ	31-Oct-25	
33	Union Gas Dawn to Parkway		170,000	GJ	varies	2.1930	$/GJ	31-Oct-31	[5]
34	Union Gas Dawn to Parkway		190,000	GJ	varies	2.1930	$/GJ	31-Oct-32	[7]

notes:
(1) - Effective November 1, 2017 GJs will be converted from LH to SH
(2) - Effective November 1, 2017 34,377 GJs will be converted from LH to SH
(3) - Contract terminates the earlier of October 31, 2017 and the inservice date of contract described at Line 15 above
(4) - This is a two year assignment effective November 1, 2015 to October 31, 2017
(5) - Contract is effective November 1, 2016
(6) - EGD is in the process of finalizing a 11 month supply arrangement for supply at Chicago that incorporates an eleven month assignment of Alliance capacity
(7) - Contract is effective November 1, 2017

	Pending Contracts to meet Peak Day in 2016			Effective Date	Expiry Date
34	Peaking Service - EDA	20,469	varies	1-Dec-15	31-Mar-16

8.6 Storage Contract Summary

Corrected: 2015-10-20
EB-2015-0114
Exhibit D1
Tab 2
Schedule 2
Page 2 of 2

Storage Summary

Third Party Storage

Contract	Annual Volum GJ's	Effective Date	Expiry Date	
A	5,055,056	April 1, 2012	March 31, 2017	
B	2,110,112	April 1, 2012	March 31, 2016[1]	
C	3,165,168	April 1, 2013	March 31, 2018	
D	2,110,112	April 1, 2012	March 31, 2018	/c
E	4,000,000	April 1, 2014	March 31, 2019	
F	1,998,945	April 1, 2014	March 31, 2016[1]	/c
G	3,000,000	April 1, 2015	March 31, 2020	
H	3,000,000	April 1, 2015	March 31, 2020	

	PJ's	Maximum Withdrawal PJ's	Deliverability PJ's	Maximum Injection PJ's	Deliverability PJ's
Total Contracted Capacity	24.4	0.4	1.64%	0.2	0.87%
EGD Regulated Storage	97.8	1.9	1.90%	0.7	0.72%

note 1 - Two third party storage contracts expire March 31, 2016. The Company intends to replace these two contracts once it has completed its Storage RFP process

8.7 Monthly UDC Report

March 2016 UDC Report

	Budget January	Budget February	Budget March	Budget April	Budget May	Budget June	Budget July	Budget August	Budget September	Budget October	Budget November	Budget December		
Forecasted Monetary Impacts in the 2016 UDCDA														
$ millions	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)
Revenue From Unutilized Capacity Released														
- Seasonal	-	-	-	-	-	-	-	-	-	-	-	-	-	
- Monthly	-	-	-	-	-	-	-	-	-	-	-	-	-	
- Daily	-	-	-	-	-	-	-	-	-	-	-	-	-	
Net Impact on Deferral Account	-	-	-	-	-	-	-	-	-	-	-	-	-	

	January	February	March	April	May	June	July	August	September	October	November	December	
Forecasted Monthly Unutilized Capacity													
PJ's -	-	-	-	-	-	-	0.0	0.0	(0.0)	-	-	-	0.0
Unutilized Capacity Released													
- Seasonal	-	-	-	-	-	-	(0.0)	(0.0)	0.0	-	-	-	(0.0)
- Monthly	-	-	-	-	-	-	-	-	-	-	-	-	-
- Daily	-	-	-	-	-	-	(0.0)	(0.0)	-	-	-	-	(0.0)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-

2015 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.	239,400	186,982	78.1%
Feb.	245,040	188,094	76.8%
Mar.	268,239	218,165	81.3%
Apr.	268,203	221,112	82.4%
May	258,006	204,230	79.2%
Jun.	253,793	198,794	78.3%
Jul.	236,753	188,904	79.8%
Aug.	230,052	182,861	79.5%
Sept.	221,799	178,926	80.7%
Oct.	252,875	197,240	78.0%
Nov.	213,374	170,850	80.1%
Dec.	174,813	144,162	82.5%
TOTAL	2,862,347	2,280,320	79.7%

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.	4,876	157,968	3.1%
Feb.	4,413	160,121	2.8%
Mar.	3,471	170,195	2.0%
Apr.	2,818	178,259	1.6%
May	3,883	170,429	2.3%
Jun.	4,657	171,966	2.7%
Jul.	4,273	147,742	2.9%
Aug.	3,066	154,340	2.0%
Sept.	3,473	149,610	2.3%
Oct.	4,004	171,644	2.3%
Nov.	2,738	143,475	1.9%
Dec.	2,641	110,048	2.4%
TOTAL	44,313	1,885,797	2.3%

Witnesses: K. Lakatos-Hayward
L. Parrington

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	2,210,465	35,266	10,216	
February	2,107,046	34,545	9,895	
March	2,152,989	37,492	10,475	
April	2,084,713	36,435	15,968	
May	2,139,514	33,962	18,281	
June	2,066,844	37,703	22,540	
July	2,037,174	42,256	22,221	
August	2,376,557	52,696	25,124	
September	2,208,056	55,178	24,896	
October	2,137,234	44,816	19,205	
November	2,149,408	37,440	17,484	
December	2,149,504	30,459	13,387	
Total	25,819,504	478,248	209,692	

**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	9,186	2,104,793	0.4%
Feb	14,957	2,106,066	0.7%
Mar	19,115	2,107,932	0.9%
Apr	11,658	2,109,493	0.6%
May	8,185	2,111,331	0.4%
Jun	7,020	2,113,385	0.3%
Jul	6,833	2,116,290	0.3%
Aug	9,296	2,118,973	0.4%
Sep	11,260	2,122,412	0.5%
Oct	11,684	2,126,028	0.5%
Nov	10,010	2,129,369	0.5%
Dec	10,108	2,132,381	0.5%
Total	129,312	25,398,453	0.5%

Witnesses: K. Lakatos-Hayward
L. Parrington

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	3,360	3,453	97.3%
Feb	2,855	2,966	96.3%
Mar	3,076	3,169	97.1%
Apr	3,145	3,263	96.4%
May	3,311	3,466	95.5%
Jun	3,713	3,892	95.4%
Jul	3,508	3,723	94.2%
Aug	3,748	3,943	95.1%
Sep	4,467	4,719	94.7%
Oct	5,393	5,738	94.0%
Nov	4,805	5,069	94.8%
Dec	3,358	3,576	93.9%
Total	44,739	46,977	95.2%

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	74	73	1 calls missed: 1 calls arrived later than 2 hours	98.6%
Feb	85	82	3 calls missed: 2 calls arrived later than 2 hours, 1 reschedule after 2 hour limit without notifying customer	96.5%
Mar	73	67	6 calls missed; 2 calls arrived later than 2 hours, 4 reschedule after 2 hour limit without notifying customer	91.8%
Apr	77	75	2 calls missed; 1 calls arrived later than 2 hours, 1 rescheduled after 2 hour limit without notifying customer	97.4%

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)
May	97	95	2 calls missed: 2 calls arrived later than 2 hours	97.9%
Jun	92	85	7 calls missed: 7 rescheduled after 2 hour limit without notifying customer	92.4%
Jul	116	112	4 calls missed: 1 calls arrived later than 2 hours, 3 rescheduled after 2 hour limit without notifying customer	96.6%
Aug	106	98	8 calls missed: 8 rescheduled after 2 hour limit without notifying customer	92.5%
Sep	147	141	6 calls missed: 2 calls arrived later than 2 hours, 4 rescheduled after 2 hour limit without notifying customer	95.9%
Oct	237	225	12 calls missed: 1 calls arrived later than 2 hours, 11 rescheduled after 2 hour limit without notifying customer	94.9%
Nov	181	171	10 calls missed: 5 calls arrived later than 2 hours, 5 rescheduled after 2 hour limit without notifying customer	94.5%

Witnesses: K. Lakatos-Hayward
L. Parrington

Dec	88	78	10 calls missed: 1 calls arrived later than 2 hours, 9 rescheduled after 2 hour limit without notifying customer	88.6%
Total	1,373	1,302	As noted above.	94.8%

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	5,179	5,383	96.2%
Feb	5,283	5,602	94.3%
Mar	4,383	4,502	97.4%
Apr	4,139	4,258	97.2%
May	3,834	3,919	97.8%
Jun	3,362	3,425	98.2%
Jul	3,302	3,357	98.4%
Aug	3,367	3,426	98.3%
Sep	3,559	3,683	96.6%
Oct	5,329	5,511	96.7%
Nov	5,356	5,620	95.3%
Dec	4,381	4,538	96.5%
Total	51,474	53,224	96.7%

Witnesses: K. Lakatos-Hayward
L. Parrington

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.	0	0	0%
Feb.	1	1	100%
Mar.	1	1	100%
Apr.	1	1	100%
May	0	0	0%
Jun.	0	0	0%
Jul.	4	4	100%
Aug.	1	1	100%
Sept.	0	0	0%
Oct.	0	0	0%
Nov.	0	0	0%
Dec.	3	3	100%
TOTAL	11	11	100%

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	727	789	92.1%
Feb	442	494	89.5%
Mar	254	290	87.6%
Apr	3,378	3,459	97.7%
May	5,863	6,006	97.6%
Jun	5,894	6,064	97.2%
Jul	2,674	2,835	94.3%
Aug	3,570	3,736	95.6%
Sep	4,319	4,579	94.3%
Oct	6,041	6,558	92.1%
Nov	2,376	2,708	87.7%
Dec	1,154	1,274	90.6%
Total	36,692	38,792	94.6%

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2015

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. 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, 2016

February 18, 2016

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, 2015 and December 31, 2014 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, 2015, 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.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and their subsidiaries as at December 31, 2015 and December 31, 2014 and its results of operations and their cash flows for each of the three years in the period ended December 31, 2015 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,	**2015**	2014	2013
(millions of Canadian dollars)			
Revenues			
Gas commodity and distribution revenue *(Note 21)*	**3,043**	2,803	2,221
Transportation of gas for customers	**344**	305	328
Other revenue *(Note 21)*	**97**	92	97
	3,484	3,200	2,646
Expenses			
Gas commodity and distribution costs *(Note 21)*	**2,322**	2,046	1,480
Operating and administrative *(Notes 19 and 21)*	**509**	493	496
Depreciation and amortization *(Notes 6 and 8)*	**290**	286	304
Earnings sharing *(Note 4)*	**7**	12	-
	3,128	2,837	2,280
	356	363	366
Other income *(Note 21)*	**70**	66	65
Interest expense, net *(Notes 10, 16 and 21)*	**(181)**	(177)	(171)
	245	252	260
Income taxes *(Note 17)*	**(11)**	(6)	(43)
Earnings	**234**	246	217
Preference share dividends *(Note 13)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**232**	244	215

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings	**234**	246	217
Other comprehensive income/(loss), net of tax *(Notes 15 and 16)*			
Change in unrealized gain/(loss) on cash flow hedges	**(18)**	(62)	81
Reclassification to earnings of realized loss on cash flow hedges	**5**	-	1
Reclassification to earnings of unrealized gain on cash flow hedges	**-**	-	(2)
Actuarial gain/(loss) on other postretirement benefits (OPEB) *(Note 18)*	**-**	(7)	10
Change in foreign currency translation adjustment	**8**	3	1
Other comprehensive income/(loss)	**(5)**	(66)	91
Comprehensive income	**229**	180	308
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**227**	178	306

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Preference shares *(Note 13)*	**100**	100	100
Common shares *(Note 13)*			
Balance at beginning of year	**1,437**	1,287	1,137
Common shares issued	**200**	150	150
Balance at end of year	**1,637**	1,437	1,287
Additional paid-in capital	**1,148**	1,148	1,148
Retained earnings			
Balance at beginning of year	**62**	22	7
Earnings attributable to the common shareholder	**232**	244	215
Common share dividends declared	**(223)**	(204)	(200)
Balance at end of year	**71**	62	22
Accumulated other comprehensive income/(loss) *(Note 15)*			
Balance at beginning of year	**(1)**	65	(26)
Other comprehensive income/(loss)	**(5)**	(66)	91
Balance at end of year	**(6)**	(1)	65
Total shareholders' equity	**2,950**	2,746	2,622

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Operating activities			
Earnings	**234**	246	217
Depreciation and amortization	**290**	286	304
Deferred income taxes	**16**	4	(9)
Refund of revenues *(Note 4)*	**(52)**	52	-
Non-cash net defined pension and OPEB obligations costs	**31**	(5)	2
Premium on issuance of term notes	**-**	-	12
Other	**(2)**	18	10
Changes in operating assets and liabilities *(Notes 3 and 20)*	**325**	(1,031)	(86)
	842	(430)	450
Investing activities			
Additions to property, plant and equipment	**(977)**	(601)	(519)
Additions to intangible assets	**(46)**	(36)	(34)
Change in construction payable	**151**	17	6
Proceeds from disposition	**8**	-	-
	(864)	(620)	(547)
Financing activities			
Change in bank indebtedness *(Note 3)*	**18**	9	(12)
Net change in short-term borrowings *(Note 10)*	**(340)**	564	(210)
Net change in short-term borrowing from affiliates *(Note 21)*	**(170)**	189	2
Term note issuance *(Note 10)*	**558**	729	400
Term note repayments	**(2)**	(400)	-
Common shares issued *(Note 13)*	**200**	150	150
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(218)**	(203)	(200)
Other	**(3)**	(2)	(2)
	41	1,034	126
Increase/(decrease) in cash and cash equivalents	**19**	(16)	29
Cash and cash equivalents at beginning of year *(Note 3)*	**17**	33	4
Cash and cash equivalents at end of year	**36**	17	33
Supplementary cash flow information			
Income taxes paid	**17**	23	42
Interest paid *(Note 10)*	**193**	191	169

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2015**	2014
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents *(Note 3)*	**36**	17
Accounts receivable and other *(Notes 4, 5, 16, and 17)*	**790**	1,178
Due from affiliates *(Note 21)*	**10**	11
Gas inventories	**547**	563
	1,383	1,769
Property, plant and equipment, net *(Notes 6 and 12)*	**7,081**	6,268
Investment in affiliate company *(Notes 16 and 21)*	**825**	825
Deferred amounts and other assets *(Notes 4, 7, and 17)*	**556**	738
Intangible assets, net *(Note 8)*	**157**	161
	10,002	9,761
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**27**	9
Short-term borrowings *(Note 10)*	**599**	938
Short-term borrowings from affiliate *(Notes 10 and 21)*	**40**	204
Accounts payable and other *(Notes 3, 4, 9, 16, and 19)*	**870**	861
Due to affiliates *(Note 21)*	**87**	95
Current maturities of long-term debt *(Note 10)*	**2**	2
	1,625	2,109
Long-term debt *(Note 10)*	**3,681**	3,125
Other long-term liabilities *(Notes 4, 11, 12 and 16)*	**847**	943
Deferred income taxes *(Note 17)*	**524**	463
Loans from affiliate company *(Notes 10 and 21)*	**375**	375
	7,052	7,015
Commitments and contingencies *(Notes 21 and 22)*		
Shareholders' equity		
Share capital *(Note 13)*		
Preference shares *(convertible; 4 outstanding at December 31, 2015 and 2014)*	**100**	100
Common shares *(170 and 159 outstanding at December 31, 2015 and 2014, respectively)*	**1,637**	1,437
Additional paid-in capital	**1,148**	1,148
Retained earnings	**71**	62
Accumulated other comprehensive loss *(Note 15)*	**(6)**	(1)
	2,950	2,746
	10,002	9,761

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).

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 5)*; allowance for doubtful accounts *(Note 5)*; carrying value of gas inventory; depreciation rates and carrying value of property, plant and equipment *(Note 6)*; amortization rates and carrying value of intangible assets *(Note 8)*; 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 OPEB *(Note 18);* commitments and contingencies *(Note 22)*; and fair value of asset retirement obligations (ARO) *(Note 12)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiary. 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 areas.

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, when it first adopted U.S. GAAP. 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, 2015 or 2014.

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. Refer to Note 3 for changes in accounting policy.

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.

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 pool method of accounting for property, plant and equipment is followed whereby similar assets with comparable useful lives are grouped and depreciated as a pool, as approved by the Regulators. 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 until the last asset in the pool is disposed of. 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; 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 issued and further revised in 2015. These assumptions were adopted by the Company for the measurement of the December 31, 2015 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. 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 records regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for rate-making purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation accounting, 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 (ISO) 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 (PSU) and Restricted Stock Units (RSU) 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.

Performance Stock Options (PSO) 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 PSOs granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period. The options become exercisable when both performance targets and the time vesting requirements have been met.

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

FUTURE ACCOUNTING POLICY CHANGES

Measurement Date of Defined Benefit Obligation and Plan Assets

Accounting Standards Update (ASU) 2015-04 was issued in April 2015 with the intent to simplify the fair value measurement of defined benefit plan assets and obligations. Where there are significant events in an interim period that would trigger a re-measurement of the plan assets and obligations, an entity is permitted to re-measure such assets and obligations using the month end that is closest to the date of the significant event. The accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs
ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires a debt issuance cost related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. Further, ASU 2015-15 was issued in August 2015 to clarify the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements, whereby the Company may defer debt issuance costs as an asset and subsequently amortize them over the term of the line-of-credit. The accounting updates are effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's 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. In July 2015, the effective date of the new standard was delayed by one year and the new standard is now effective for annual and interim periods beginning on or after December 15, 2017 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.

Classification of Deferred Taxes on the Statement of Financial Position
ASU 2015-17 was issued in November 2015 with the intent to simplify the presentation of deferred income taxes. The amendments eliminate the current requirement to present deferred tax assets and liabilities as current and noncurrent. The amendments require that all deferred tax assets and liabilities be classified as noncurrent in a classified statement of financial position. The accounting update is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years and is to be applied on a prospective basis. Early application is permitted for all entities as of the beginning of an interim or annual reporting period. Effective January 1, 2016, the Company will elect to early adopt ASU 2015-17. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Recognition and Measurement of Financial Assets and Liabilities
ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the consolidated Statement of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Simplifying the Measurement of Inventory
ASU 2015-11 was issued in July 2015 with the intent to simplify the measurement of inventory. The new standard requires inventory to be measured at the lower of cost and net realizable value and is applicable to all inventory, with the exception of inventory measured using last-in, first-out or the retail inventory method. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim reporting periods beginning after December 15, 2016 and is to be applied on a prospective basis.

CHANGES IN ACCOUNTING POLICY

Book Overdrafts
Prior to January 2015, the Company recorded all obligations for which cheques were issued but not presented to the financial institution in Accounts payable and other. Effective January 2015, the Company changed the accounting policy and began presenting only book overdrafts in Accounts payable and other. Comparative figures presented in the audited consolidated financial statements for the year ended December 31, 2015 have been retrospectively revised. The change in accounting policy did not have a material impact on the audited Consolidated Statements of Financial Position and audited Consolidated Statements of Cash Flows for previously issued financial statements. There was no impact to the audited Consolidated Statement of Earnings. The change in accounting policy allows for the Company to account for its book overdrafts in a preferable method.

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.

RECENT RATE APPROVALS

Enbridge Gas Distribution
For the year ended December 31, 2015, Enbridge Gas Distribution’s rates were set according to the OEB approved settlement agreement (April 2015) and final rate order (May 2015). The rates approved as part of the 2015 rate application represented the second year of the Company’s customized incentive regulation (IR) plan, which set rates for the period of 2014 to 2018 and was approved by the OEB in July and August 2014.

For the year ended December 31, 2014, Enbridge Gas Distribution’s rates were set by the OEB’s July 2014 decision, and subsequent August 2014 decision and rate order in the Company’s customized IR application. The decisions and rate order established final 2014 allowed revenues and billing rates, as well as placeholder allowed revenues for 2015 through 2018. The customized IR plan requires Enbridge Gas Distribution to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates. The customized IR decision also approved the adoption of a new approach for determining net negative salvage percentages as a component of the Enbridge Gas Distribution’s depreciation rates in addition to Enbridge Gas Distribution shares earnings above the approved base return, equally with customers.

Under the customized IR plan, the Company has continued 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 on a cost of service (COS) basis pursuant to an OEB approved settlement agreement.

St. Lawrence Gas
For the years ended December 31, 2015, 2014 and 2013, 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. 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.

During the years ended December 31, 2015, 2014 and 2013, the cost of natural gas was passed on to customers as a flow-through.

APPROVED RETURNS ON EQUITY

Enbridge Gas Distribution

Enbridge Gas Distribution's rates for 2015 included an after-tax rate of return on common equity of 9.30% (2014 - 9.36% and 2013 - 8.93%) based on a 36% (2014 and 2013 - 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, 2015 (2014 and 2013 - 10.5%) based on a 50% (2014 and 2013 - 50%) deemed common equity component of rate base. Any earnings above a return on equity of 11% (2014 and 2013 - 11%) were shared equally with customers. The calculation of such earnings was cumulative from January 1, 2010 to December 31, 2015 and resulted in no sharing impact as at December 31, 2015 (2014 and 2013 - nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation accounting, 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 accounting, 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,	**2015**	2014	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes[1]	**324**	270	AP/DA	*
Purchased gas variance[2]	**129**	673	AR	1
OPEB[3]	**75**	84	AR/DA	17
Unabsorbed demand cost[4]	**66**	14	AR	*
Constant dollar net salvage adjustment[5]	**42**	37	DA	*
Pension plans, net[6]	**30**	90	DA/OLTL	*
Customer care CIS rate smoothing deferral[7]	**9**	8	AR/DA	3
Demand side management incentive[8]	**8**	13	AR	*
Storage and transportation deferral[9]	**5**	(3)	AR	1
Unaccounted for gas variance[10]	**3**	13	AR	1
Design day criteria transportation[11]	**-**	13	-	*
Revenue adjustment[12]	**-**	(52)	-	*
Future removal and site restoration reserves[13]	**(553)**	(536)	OLTL	*
Site restoration clearance adjustment[14]	**(193)**	(283)	AP/OLTL	3
Transactional services deferral[15]	**(9)**	(26)	AP	1
Earnings sharing deferral[16]	**(6)**	(12)	AP	*
Average use true-up variance[17]	**(2)**	1	AP	1
Post-retirement true-up variance[18]	**(1)**	(3)	AP	*
Other regulatory assets and liabilities, net	**3**	(1)	***	***
	(70)	300		
St. Lawrence				
Other regulatory assets and liabilities, net	**6**	5	***	***
	(64)	305		

* Refer to the footnote for details

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

*** Dependent on the nature of the item

1 *The 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 accounting, this regulatory balance and the related earnings impact would not be recorded.*

2 *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 accounting, the actual cost of natural gas would be included in Gas commodity and distribution costs, and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

3 *The OPEB balance represents the Company's right to recover OPEB costs pursuant to an OEB rate order, which allows the amount as at December 31, 2013 to be collected in rates over a 20-year period commencing in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

4 *The Unabsorbed demand cost deferral account (UDCDA) represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet requirements resulting from its 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 accounting, these costs would be expensed as incurred.

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 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 accounting, 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.*

7 *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 accumulated 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 will be lowered 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 accounting, the variance would be included in earnings in the year incurred.*

8 *Demand side management incentive deferral account (DSMIDA) 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 accounting.*

9 *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 accounting, 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.*

10 *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 accounting, this variance would be included in earnings in the year incurred.*

11 *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 accounting, these costs would be expensed as incurred.*

12 *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 that was refunded to customers in January 2015. There would be no change in the treatment of this item in the absence of rate regulation accounting.*

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 that is recorded in rates. 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 accounting, 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 accounting.*

15 *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 accounting.*

16 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the customized IR plan. The Earnings sharing is payable to customers and represents 50% of normalized U.S. GAAP utility earnings represented by an ROE in*

excess of the allowed utility ROE applicable to Enbridge Gas Distribution, as determined for each year of the customized IR plan. There would be no change in the treatment of this item in the absence of rate regulation accounting.

17 *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 accounting, this regulatory balance and the related earnings impact would not be recorded.*

18 *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 accounting, 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.

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 accounting, 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, 2015, cumulative costs relating to this services contract of $174 million (2014 - $166 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment
In the absence of rate regulation accounting, 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/disposal 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, 2015, the net book value of these costs was $48 million (2014 - $60 million). In the absence of rate regulation accounting, 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, 2015 is $40 million (2014 - $42 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 accounting, 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 accounting, depreciation rates would not have included a charge for future removal and site restoration costs.

5. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Trade receivables	**309**	372
Regulatory assets *(Note 4)*	**216**	567
Unbilled revenues	**151**	161
Agent billing and collection receivable	**39**	-
Sundry receivables	**28**	22
Taxes receivable	**19**	28
Current deferred income taxes *(Note 17)*	**18**	23
Prepaid expenses	**11**	8
Other	**33**	30
Allowance for doubtful accounts *(Note 16)*	**(34)**	(33)
	790	1,178

During the first half 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 Regulatory assets as at December 31, 2015 is $129 million (December 31, 2014 - $491 million) which represents the PGVA balance that is expected to be recovered from customers within the next 12 months.

6. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2015**	2014
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**3,740**	3,593
Gas services	**2.3%**	**2,929**	2,798
Regulating and metering equipment	**5.7%**	**848**	825
Gas storage	**2.1%**	**327**	323
Right-of-way	**1.0%**	**52**	52
Computer technology	**37.5%**	**31**	40
Under construction	**-**	**893**	307
Construction materials inventory	**-**	**40**	39
Land	**-**	**24**	24
Other	**6.9%**	**303**	289
		9,187	8,290
Accumulated depreciation		**(2,197)**	(2,115)
		6,990	6,175
Unregulated property, plant and equipment			
Gas storage	**2.1%**	**88**	88
Other	**8.6%**	**27**	27
		115	115
Accumulated depreciation		**(24)**	(22)
		91	93
Property, plant and equipment, net		**7,081**	6,268

Depreciation expense, including amounts collected for future removal and site restoration costs, was $239 million for the year ended December 31, 2015 (2014 - $237 million, 2013 - $267 million).

7. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory assets *(Note 4)*	**526**	711
Deferred financing costs	**13**	12
Pension and OPEB asset *(Note 18)*	**8**	4
Deferred income taxes *(Note 17)*	**8**	8
Other	**1**	3
	556	738

At December 31, 2015, deferred financing costs of $29 million (2014 - $34 million) were subject to amortization and are presented net of accumulated amortization of $16 million (2014 - $22 million). Amortization expense for the year ended December 31, 2015 was $2 million (2014 and 2013 - $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 Regulatory assets at December 31, 2015 is nil (2014 - $182 million) which represents the portion of the PGVA balance that is expected to be recovered beyond the next 12 months.

8. INTANGIBLE ASSETS

December 31, 2015	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**23.2%**	**238**	**(129)**	**109**
CIS	**10.0%**	**127**	**(79)**	**48**
		365	**(208)**	**157**

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

Intangible assets include $61 million of work-in-progress as at December 31, 2015 (2014 - $23 million). Total amortization expense for intangible assets was $51 million for the year ended December 31, 2015 (2014 - $49 million, 2013 - $37 million). The Company expects aggregate amortization expense for the years ending December 31, 2016 through 2020 of $58 million, $47 million, $45 million, $41 million and $32 million, respectively.

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Accrued liabilities	**396**	351
Regulatory liabilities *(Note 4)*	**136**	233
Budget billing plan payable	**105**	137
Trade payables	**62**	17
Security deposits	**61**	61
Contractual holdbacks	**38**	7
Interest payable	**33**	27
Short-term portion of derivative liabilities *(Note 16)*	**14**	6
Taxes payable	**9**	11
Current portion of OPEB liability *(Note 18)*	**4**	4
Agent billing and collection payable	**-**	2
Dividends payable	**1**	1
Other	**11**	4
	870	861

Included in Regulatory liabilities at December 31, 2015 is $84 million (2014 - $90 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers within the next 12 months. Also included in Regulatory liabilities at December 31, 2015 is nil (2014 - $52 million) relating to the refund of revenues to customers.

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2015**	2014
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes	4.56%	2017-2050	**3,595**	3,025
Commercial paper and credit facility draws, net[1]			**607**	1,122
Other[2]			**35**	37
Total debt			**4,322**	4,269
Current maturities			**(2)**	(2)
Short-term borrowings	0.81%		**(599)**	(938)
Short-term borrowings from affiliates *(Note 21)*	0.80%		**(40)**	(204)
Long-term debt			**3,681**	3,125
Loans from affiliate company *(Note 21)*			**375**	375

1 *Includes amounts drawn on uncommitted demand credit facilities.*
2 *Consists of note payable to affiliate company and debt premium.*

In September 2015, the Company issued $400 million of 10-year medium-term notes at an interest rate of 3.31% and an additional $170 million of medium-term notes under the same terms as the August 2044 30-year medium-term note pricing supplement issued in August 2014 at an interest rate of 4.00%.

In December 2015, a new $1.5 billion shelf prospectus was filed as a continuation of the Company's medium-term note program, which was previously renewed in June 2014. The prospectus is effective for a 25-month period.

For the years ending December 31, 2016 through 2020, medium-term note maturities are $2 million, $502 million, $2 million, $2 million and $400 million, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2016 through 2020 are $171 million, $169 million, $156 million, $156 million and $155 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Debentures and medium-term notes	**158**	149	138
Loans from affiliate company *(Note 21)*	**27**	29	27
Commercial paper and credit facility draws	**8**	9	4
Other interest and finance costs	**9**	(4)	9
Capitalized	**(21)**	(6)	(7)
	181	177	171

In 2015, total interest paid to third parties was $166 million (2014 - $163 million, 2013 - $142 million) and total interest paid to affiliate company and related party was $27 million (2014 - $29 million, 2013 - $27 million).

The Company's borrowings, whether debentures or medium-term notes, are unsecured. As at December 31, 2015, the Company was in compliance with all covenants.

CREDIT FACILITIES

The Company currently has a $1 billion commercial paper program limit that is backstopped by committed lines of credit of $1 billion. 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 July 2015, the Company extended the term out date of this external credit facility to July 2016, with a maturity date in July 2017.

The Company also has a $300 million revolving credit facility from Enbridge. In June 2015, the Company extended the term out date to May 2016 on this revolving credit facility, with a maturity date in May 2017. As at December 31, 2015, no amounts were drawn on this credit facility.

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

				December 31, 2015	December 31, 2014
	Maturity Dates	Total Facilities[1]	Draws[2]	Available	Total Facilities[1]
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2017	**1,300**	**595**	**705**	1,300
St. Lawrence Gas Company, Inc.	2019	**10**	**8**	**2**	8
Total credit facilities		**1,310**	**603**	**707**	1,308

1 *Includes a $300 million revolving credit facility from the Company's ultimate parent, Enbridge and matures in May 2017.*
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 also has $7 million (2014 - $6 million) of uncommitted demand credit facilities, of which $3 million (2014 - $2 million) was unutilized as at December 31, 2015.

Credit facilities carried a weighted average standby fee of 0.2% on the unused portion and draws bear interest at market rates.

11. OTHER LONG-TERM LIABILITIES

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory liabilities *(Note 4)*	**670**	740
Pension and OPEB liabilities *(Note 18)*	**163**	190
Long-term portion of derivative liabilities *(Note 16)*	**-**	5
Other *(Note 12)*	**14**	8
	847	943

Included in Regulatory liabilities at December 31, 2015 is $109 million (2014 - $193 million) relating to the portion of site restoration clearance adjustment that is expected to be refunded to customers beyond the next 12 months.

12. ASSET RETIREMENT OBLIGATIONS

The liability for the expected cash flows as recognized in the consolidated financial statements reflected discount rates ranging from 1.65% to 3.77% (2014 - 1.65% to 3.77%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Obligations at beginning of year	**9**	6
Liabilities settled	**(2)**	-
Change in estimate	**2**	3
Accretion expense	**-**	-
Obligations at end of year	**9**	9
Presented as follows:		
Other long-term liabilities *(Note 11)*	**9**	9
	9	9

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

	2015		2014		2013	
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	**158.9**	**1,437**	150.6	1,287	142.3	1,137
Common shares issued	**11.1**	**200**	8.3	150	8.3	150
Balance at end of year	**170.0**	**1,637**	158.9	1,437	150.6	1,287

PREFERENCE SHARES

December 31, 2015, 2014, and 2013	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, 2015, 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 PSO 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, 2015, the Company did not have any employees that had options in the PSO 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, 2015	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	**2,665**	**33.53**		
Options granted	**458**	**59.08**		
Options exercised[1]	**(422)**	**23.20**		
Options cancelled	**(16)**	**44.94**		
Employee movements from other Enbridge companies	**3**	**18.24**		
Options outstanding at end of year	**2,688**	**39.43**	**6.3**	**45**
Options vested at end of year[2]	**1,560**	**30.85**	**4.9**	**40**

1 *The total intrinsic value of ISOs exercised during the year ended December 31, 2015 was $14 million (2014 - $11 million; 2013 - $7 million) and cash received by Enbridge on exercise was $10 million (2014 - $5 million; 2013 - $2 million).*

2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2015 was $2 million (2014 and 2013 - $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,	**2015**	2014	2013
Fair value per option *(Canadian dollars)*[1]	**6.48**	5.53	5.27
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**19.9%**	16.9%	17.4%
Expected dividend yield[4]	**3.2%**	2.9%	2.8%
Risk-free interest rate[5]	**0.9%**	1.6%	1.2%

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 $6.22 (2014 - $5.45; 2013 - $5.15) for Canadian employees and US$6.22 (2014 - US$5.35, 2013 - US$5.63) 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, 2015 for ISOs was $4 million (2014 - $4 million; 2013 - $3 million). At December 31, 2015, 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 2013, 2014 and 2015 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 2015 expense, multipliers of two, based upon multiplier estimates at December 31, 2015, were used for each of the 2013, 2014 and 2015 PSU grants.

December 31, 2015	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	**26**		
Units granted	**14**		
Units matured[1]	**(11)**		
Dividend reinvestment	**1**		
Units outstanding at end of year	**30**	**1.5**	**3**

1 The total amount paid by Enbridge during the year ended December 31, 2015 for PSUs was $2 million (2014 - $1 million; 2013 - $2 million).

Compensation expense recorded for the year ended December 31, 2015 for PSUs was $2 million (2014 - $5 million; 2013 - $4 million). As of December 31, 2015, 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, 2015	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	**196**		
Units granted	**81**		
Units cancelled	**(9)**		
Units matured[1]	**(96)**		
Dividend reinvestment	**10**		
Employee movements from other Enbridge companies	**2**		
Units outstanding at end of year	**184**	**1.4**	**11**

1 The total amount paid by Enbridge during the year ended December 31, 2015 for RSUs was $5 million (2014 and 2013 - $5 million).

Compensation expense recorded for the year ended December 31, 2015 for RSUs was $6 million (2014 and 2013 - $5 million). As of December 31, 2015, 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, 2015, 2014 and 2013, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2015	**8**	**(2)**	**(7)**	**(1)**
Other comprehensive income retained in AOCI	**(24)**	**8**	**-**	**(16)**
Other comprehensive loss reclassified to earnings	**6**	**-**	**-**	**6**
Income tax on amounts retained in AOCI	**6**	**-**	**-**	**6**
Income tax on amounts reclassified to earnings	**(1)**	**-**	**-**	**(1)**
	(13)	**8**	**-**	**(5)**
Balance at December 31, 2015	**(5)**	**6**	**(7)**	**(6)**

	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/(loss) retained in AOCI	(84)	3	(9)	(90)
Other comprehensive income reclassified to earnings	-	-	-	-
Income tax on amounts retained in AOCI	22	-	2	24
	(62)	3	(7)	(66)
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 loss reclassified to earnings	(1)	-	-	(1)
Income tax on amounts retained in AOCI	(28)	-	(4)	(32)
	80	1	10	91
Balance at December 31, 2013	70	(5)	-	65

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.

The Company generates certain revenues, and holds a subsidiary that is denominated in a currency other than Canadian dollars. As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

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 Company has no net exposure to movements in the foreign exchange rate on natural gas purchases.

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.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge. The Company does not typically manage the fair value of its debt instruments.

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 (2014 - 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 or net investment hedges at December 31, 2015 or 2014.

The Company generally has a common practice 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, 2015	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	**(14)**	**-**	**(14)**	**-**	**(14)**
Other long-term liabilities					
Interest rate contracts	**-**	**-**	**-**	**-**	**-**
Total net derivative liability					
Interest rate contracts	**(14)**	**-**	**(14)**	**-**	**(14)**

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)

The Company's derivatives instruments mature through 2017 and have a notional principal of $154 million for interest rate contracts for short-term borrowings (2014 - $346 million), and $162 million for interest rate contracts on long-term debt (2014 - $422 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,	**2015**	2014	2013
(millions of Canadian dollars)			
Amount of unrealized (loss)/gain recognized in OCI			
Cash flow hedges			
Interest rate contracts	**(24)**	(84)	109
	(24)	(84)	109
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(2)**	-	(2)
	(2)	-	(2)
Amount of (loss)/gain reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**(4)**	-	2
	(4)	-	2

1 Reported within Interest expense, net in the Consolidated Statements of Earnings.

The Company estimates that $3 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 13 months at December 31, 2015.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 21 and 22)* 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 its ultimate parent, Enbridge, 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 MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. In addition to the Company's access to the Canadian public capital markets, the Company maintains committed credit facilities *(Note 10)* 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, 2015. 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 5),* which totaled $34 million at December 31, 2015 (December 31, 2014 - $33 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 did not have group credit concentration and maximum credit exposure, with respect to derivative instruments, in the Canadian financial institutions or European financial institutions counterparty segments at December 31, 2015 and 2014.

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, 2015, the Company had Level 2 derivative assets with fair value of nil (2014 - nil), and Level 2 derivative liabilities with fair value of $14 million (2014 - $11 million).

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, 2015 or 2014.

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, 2015, the fair value of the investment was $825 million (2014 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as of December 31, 2015 and 2014 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, 2015, the Company's long-term debt had a carrying value of $3,683 million (2014 - $3,127 million) and a fair value of $4,159 million (2014 - $3,709 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,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings before income taxes	**245**	252	260
Federal statutory income tax rate	**15.0%**	15.0%	15.0%
Federal income taxes at statutory rate	**37**	38	39
Increase/(decrease) resulting from:			
Provincial and state income taxes	**5**	3	19
Effects of rate regulated accounting[1]	**(22)**	(25)	(5)
Non-taxable intercompany distributions	**(9)**	(9)	(9)
Other[2]	**-**	(1)	(1)
Income taxes	**11**	6	43
Effective income tax rate	**4.5%**	2.4%	16.5%

1 During 2015 and 2014, previously collected costs for future removal and site restoration were refunded to customers that resulted in a decrease in income taxes of $24 million at December 31, 2015 (2014 - $26 million).

2 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,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings before income taxes			
Canada	**243**	249	258
United States	**2**	3	2
	245	252	260
Current income taxes			
Canada	**(4)**	2	51
United States	**(1)**	1	1
	(5)	3	52
Deferred income taxes			
Canada	**14**	3	(9)
United States	**2**	-	-
	16	3	(9)
Income taxes	**11**	6	43

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,	**2015**	2014
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(600)**	(577)
Financial derivatives	**-**	(3)
Regulatory assets	**(86)**	(72)
Other	**(1)**	(1)
Total deferred income tax liabilities	**(687)**	(653)
Deferred income tax assets		
Future removal and site restoration reserves	**146**	143
Deferrals	**-**	53
Retirement and postretirement benefits	**30**	21
Minimum tax credits	**9**	-
Financial derivatives	**2**	-
Other	**2**	4
Total deferred income tax assets	**189**	221
Net deferred income tax liabilities	**(498)**	(432)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 5)*	**18**	23
Deferred amounts and other assets *(Note 7)*	**8**	8
Total deferred income tax assets	**26**	31
Liabilities		
Deferred income taxes	**(524)**	(463)
Total deferred income tax liabilities	**(524)**	(463)
Net deferred income tax liabilities	**(498)**	(432)

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, 2015.

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 $30 million (2014 - $21 million). If such earnings 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 2011 to 2014 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, 2015 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,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,046**	875	**117**	100
Service cost	**35**	25	**1**	2
Interest cost	**41**	43	**5**	6
Actuarial loss/(gain)	**(54)**	142	**(1)**	12
Benefits paid	**(43)**	(41)	**(4)**	(3)
Other	**-**	2	**2**	-
Benefit obligation at end of year	**1,025**	1,046	**120**	117
Change in plan assets				
Fair value of plan assets at beginning of year	**960**	866	**13**	9
Actual return on plan assets	**49**	96	**-**	2
Employer's contributions	**3**	41	**5**	5
Benefits paid	**(43)**	(41)	**(4)**	(3)
Other	**-**	(2)	**3**	-
Fair value of plan assets at end of year	**969**	960	**17**	13
Underfunded status at end of year	**(56)**	(86)	**(103)**	(104)
Presented as follows:				
Deferred amounts and other assets *(Note 7)*	**6**	4	**2**	-
Accounts payable and other *(Note 9)*	**-**	-	**(4)**	(4)
Other long-term liabilities *(Note 11)*	**(62)**	(90)	**(101)**	(100)

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,	**2015**	2014	2013	**2015**	2014	2013
Discount rate	**4.2%**	4.0%	5.0%	**4.2%**	4.0%	5.0%
Average rate of salary increases	**3.4%**	3.7%	3.5%	**3.4%**	3.7%	3.5%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2015**	2014	2013	**2015**	2014	2013
(millions of Canadian dollars)						
Benefits earned during the year	**35**	25	25	**1**	1	1
Interest cost on projected benefit obligations	**41**	43	38	**5**	6	4
Expected return on plan assets	**(62)**	(59)	(52)	**(1)**	(1)	(1)
Amortization of prior service costs	**-**	-	1	**-**	-	-
Amortization of actuarial loss	**19**	16	28	**1**	-	2
Net defined benefit costs on an accrual basis	**33**	25	40	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**34**	26	41	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**-**	9	(14)
Total amount recognized in OCI	**-**	-	-	**-**	9	(14)
Total net benefit cost on an accrual basis and amount recognized in OCI	**34**	26	41	**6**	15	(8)

1 *Unamortized actuarial losses included in AOCI, before tax, were $9 million relating to OPEB at December 31, 2015 (2014 - $9 million, 2013 - nil).*

The Company estimates that approximately $13 million related to pension plans and OPEB at December 31, 2015 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Actuarial loss	**13**	**-**	**13**
	13	**-**	**13**

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.

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, 2015, an offsetting regulatory asset of nil (2014 - regulatory liability of $6 million) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

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,	**2015**	2014	2013	**2015**	2014	2013
Discount rate	**4.0%**	5.0%	4.3%	**4.0%**	5.0%	4.3%
Average rate of return on pension plan assets	**6.8%**	6.8%	6.8%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.7%**	3.5%	3.5%	**3.7%**	3.5%	3.5%

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 $12 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 $10 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,	**2015**	2014	**2015**	2014
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, 2015, the pension assets were invested in 47% (2014 - 55%) in equity securities, 36% (2014 - 36%) in fixed income securities and 17% (2014 - 9%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $29 million (2014 - $18 million) have been excluded from the table below.

	2015				2014			
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	**10**	**-**	**-**	**10**	14	-	-	14
Fixed income securities								
Canadian government real return bonds	**73**	**-**	**-**	**73**	71	-	-	71
Canadian corporate bond index fund	**133**	**-**	**-**	**133**	137	-	-	137
Canadian government bond index fund	**128**	**-**	**-**	**128**	131	-	-	131
Corporate bonds and debentures	**4**	**-**	**-**	**4**	4	-	-	4
United States debt index fund	**2**	**-**	**-**	**2**	2	-	-	2
Equity								
Canadian equity securities	**71**	**-**	**-**	**71**	71	-	-	71
Canadian equity funds	**128**	**-**	**-**	**128**	137	-	-	137
United States equity securities	**1**	**-**	**-**	**1**	1	-	-	1
United States equity funds	**100**	**-**	**-**	**100**	77	19	-	96
Global equity funds	**71**	**79**	**-**	**150**	149	63	-	212
Infrastructure [4]	**-**	**-**	**96**	**96**	-	-	30	30
Real estate[5]	**-**	**-**	**51**	**51**	-	-	39	39
Forward currency contracts	**-**	**(7)**	**-**	**(7)**	-	(3)	-	(3)
	721	**72**	**147**	**940**	794	79	69	942
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**6**	**-**	**-**	**6**	5	-	-	5
Equity								
United States equity fund	**5**	**-**	**-**	**5**	4	-	-	4
Global equity fund	**5**	**-**	**-**	**5**	3	-	-	3
	17	**-**	**-**	**17**	13	-	-	13

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 and IFM Global Infrastructure (Canada) L.P. are established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd and MetLife Core Property Fund L.P. are 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,	**2015**	2014
(millions of Canadian dollars)		
Balance at beginning of year	**69**	67
Unrealized and realized gains	**26**	15
Purchases and settlements, net	**52**	(13)
Balance at end of year	**147**	69

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Total contributions	**4**	41	**5**	5

The contributions expected to be paid in 2016 for pension is $4 million and for OPEB is $4 million.

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2016	2017	2018	2019	2020	2021-2025
(millions of Canadian dollars)						
Expected future benefit payments	48	50	52	54	56	310

19. SEVERANCE COSTS

Included in Operating and administrative expense is $12 million in severance costs related to one-time termination benefits to employees. This resulted from an Enbridge-wide reduction of workforce that occurred in November 2015 that affected approximately 5% of Enbridge's workforce.

In 2015, $4 million was paid with the remaining $8 million to be paid in 2016 and is included in Accounts payable and other as at December 31, 2015.

20. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Regulatory assets	**532**	(732)	(31)
Regulatory liabilities[1]	**(178)**	(102)	2
Accounts receivable and other[2,3]	**34**	24	(13)
Gas inventories	**17**	(181)	(41)
Deferred amounts and other assets[2]	**-**	(3)	(2)
Accounts payable and other[2,3]	**(84)**	(92)	80
Other long-term liabilities[2]	**4**	55	(81)
	325	(1,031)	(86)

1 Excludes the refund of revenues paid to customers in January 2015.
2 The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.
3 Includes amounts related to affiliated companies.

21. RELATED PARTY TRANSACTIONS

All related party 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,	**2015**	2014	2013
(millions of Canadian dollars)			
Enbridge Energy Distribution Inc.			
Common share dividends declared	**223**	204	200
IPL System Inc. *(Note 16)*			
Dividend income	**63**	63	63
Interest expense *(Note 10)*	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**50**	41	38
Interest expense *(Note 10)*	**-**	2	-
Tidal Energy Marketing Inc.			
Purchase of natural gas	**23**	41	30
Revenue from optimization services	**7**	7	4
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**24**	57	21
Aux Sable Canada LP			
Purchase of natural gas	**62**	16	-
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**40**	31	30
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**28**	27	24
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**28**	26	26
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**22**	20	19
Niagara Gas Transmission Limited			
Purchase of gas transportation services	**2**	2	2

The Company had related party balances as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**1,637**	1,437
Dividend payable	**56**	51
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.)	**40**	29
Credit facility to affiliate company		
Enbridge	**-**	175
Other accounts receivable/(payable)		
Gazifère Inc.	**3**	6
Enbridge Employee Services Inc.	**(13)**	-
Enbridge	**(4)**	(7)
Tidal Energy Marketing (U.S.) LLC	**(4)**	(3)
Alliance Pipeline Limited Partnership (Canadian)	**(2)**	(2)
Aux Sable Canada LP	**(2)**	(8)
Alliance Pipeline Limited Partnership (U.S.)	**(2)**	(2)
Vector Pipeline Limited Partnership (U.S.)	**(1)**	(2)
Enbridge Pipelines Inc.	**-**	(15)
Tidal Energy Marketing Inc.	**-**	(3)
Other accounts receivable	**2**	-
Other accounts payable	**(1)**	-

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, 2015, the investment of $825 million (2014 - $825 million) in these shares resulted in a weighted average dividend yield of 7.60%.

At December 31, 2015, 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, 2015, interest paid amounted to $27 million (2014 - $27 million).

The Company has a $300 million revolving credit facility with Enbridge with a maturity date in May 2017. At December 31, 2015, the total drawings on the revolving credit facility were nil (2014 - $175 million). For the year ended December 31, 2015, interest paid amounted to nil (2014 - $2 million).

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

Treasury and Other Management Services

Enbridge provides treasury and other management services and charges the Company 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, and Niagara Gas Transmission Limited. Contractual obligations under these contracts are 2016 to 2017 - $71 million, 2018 to 2019 - $20 million and thereafter - nil.

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 shared corporate services to affiliates on a fully-allocated cost basis. Market prices, if they are reasonably determinable, are charged for affiliate services that are not shared corporate services. 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
The Company and affiliates invoice on a monthly basis and amounts are due and paid on a monthly basis.

22. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $5,722 million. The amounts which are expected to be paid in the next five years are $1,354 million, $942 million, $595 million, $566 million, and $487 million, respectively, and $1,778 million thereafter.

Minimum future payments under operating leases are estimated at $4 million in aggregate. Estimated annual lease payments for the years ended December 31, 2016 through 2020 are $4 million, nil, nil, 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, 2015, 2014 and 2013.

The Company, Enbridge, and Enbridge Pipeline Inc., in aggregate, have access to $95 million of letters of credit that they can issue, of which $37 million was unutilized as of December 31, 2015. The total outstanding letters of credit that related to the Company as of December 31, 2015 was $5 million. The Company had access to $75 million of letters of credit that it could issue, of which $51 million was unutilized as of December 31, 2014. The total outstanding letters of credit that related to the Company as of December 31, 2014 was $24 million.

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, a former owner of part of the Historic Distillery District (Wyndham Court Canada Inc.) commenced an action in the Ontario Court of Justice (General Division) against the Company alleging that coal tar originating from the Company's Station A MGP in Toronto had migrated to its lands. The Company entered into a Tolling Agreement with Wyndham Court Canada Inc. pursuant to which this action was discontinued, without prejudice to the right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham Court Canada Inc. 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 2015 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 significant 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, 2015

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 18, 2016 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, 2015, 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 and MD&A prepared for the year ended December 31, 2014. 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.

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'', ''likely'' 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 and demand for natural gas; prices of natural gas; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; and weather. Assumptions regarding the expected supply and demand of natural gas and the prices of natural gas are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates, may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, 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 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 MEASURES

This MD&A contains references to adjusted earnings, which represent earnings attributable to the common shareholder adjusted for weather and gains or losses on the settlement of pre-issuance hedge contracts during the applicable period. This MD&A also 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. Management believes that the presentation of these measures provides useful information to investors and shareholders 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 adjusted earnings are not measures that have standardized meanings prescribed by U.S. GAAP and are not considered U.S. GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers.

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.

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.

PERFORMANCE OVERVIEW

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to the common shareholder[1]	**232**	244	215
Cash flow data			
Cash provided by/(used) continuing operations	**842**	(430)	450
Cash used by investing activities	**(864)**	(620)	(547)
Cash provided by financing activities	**41**	1,034	126
Dividends			
Common share dividends declared	**223**	204	200
Dividends declared per common share	**1.38**	1.34	1.37
Preference share dividends declared	**2**	2	2
Dividends declared per preference share	**0.56**	0.60	0.60
Total revenues			
Gas commodity and distribution revenues	**3,043**	2,803	2,221
Transportation of gas for customers	**344**	305	328
Other revenue	**97**	92	97
Total revenues	**3,484**	3,200	2,646
Total assets	**10,002**	9,761	8,368
Total long-term liabilities	**5,427**	4,906	4,195

1. *Earnings per share is not provided, since the issuer is an indirect wholly owned subsidiary of Enbridge.*

HIGHLIGHTS

Year ended December 31,	**2015**	2014	2013
Number of active customers[1] *(thousands)*	**2,129**	2,098	2,065
Heating degree days[2]			
Actual	**3,710**	4,044	3,746
Forecasted based on normal weather	**3,536**	3,517	3,668
Volumetric statistics *(millions of cubic metres)*			
Gas commodity sales	**7,631**	8,209	7,365
Transportation of gas for customers	**4,327**	4,462	4,553
Unbundled volumes[3]	**406**	382	378
Total volume	**12,364**	13,053	12,296

1. *Number of active customers is the number of natural gas consuming customers at the end of the year.*
2. *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.*
3. *Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.*

EARNINGS ATTRIBUTABLE TO THE COMMON SHAREHOLDER

Earnings attributable to the common shareholder were $232 million for the year ended December 31, 2015 compared with $244 million for the year ended December 31, 2014. The decrease was primarily due to warmer weather and higher employee severance costs. This is partially offset by higher distribution charges and customer growth.

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 charges and earnings sharing in 2014.

ADJUSTED EARNINGS

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings attributable to the common shareholder	**232**	244	215
Colder than normal weather (after-tax impact)	**(11)**	(36)	(9)
Loss on settlement of pre-issuance hedge contracts	**3**	-	-
Adjusted earnings[1]	**224**	208	206

1 For more information on this non-GAAP measure see page 2.

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 approved within the Company's 2014 to 2018 customized incentive regulation (IR) proceeding, the degree day forecast for the Greater Toronto Area (GTA) utilizes a combination of a 10-year moving average method and 20-year trend method.

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. The gains or losses as a result of the settlement of pre-issuance hedge contracts represent the ineffective portion upon settlement. Adjusted earnings exclude the impacts of the settlement within earnings attributable to the common shareholder, in order to match the associated gains or losses with the debt's interest costs. The gains or losses will be amortized back into adjusted earnings over the term of the related debt.

Adjusted earnings were $224 million for the year ended December 31, 2015 compared with $208 million for the year ended December 31, 2014. The increase primarily resulted from higher distribution charges and customer growth, partially offset by higher employee severance costs.

Adjusted earnings 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 charges and earnings sharing in 2014.

REVENUES

Revenues for the year ended December 31, 2015 were $3,484 million compared with $3,200 million for the year ended December 31, 2014. The increase in revenues was primarily due to higher distribution charges, customer growth and an increase in Other revenue mainly due to higher demand side management incentive (DSMIDA) revenue. This was partially offset by warmer weather.

Revenues 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 was primarily due to colder weather, customer growth, and higher commodity prices. This was partially offset by lower distribution charges and a decrease in Other revenue mainly due to lower DSMIDA revenue.

RECENT DEVELOPMENTS

2016 RATE APPLICATION

In August 2015, the Company filed an application with the OEB for the setting of rates for 2016. The 2016 application was filed in accordance with the approved customized IR plan, and represents the third year of a five-year term. In December 2015, the OEB issued its decision and interim rate order in relation to the 2016 rate application. The decision and interim rate order approved a complete settlement agreement of all aspects of the application, including the implementation of interim 2016 rates effective January 1, 2016. Rates were deemed interim and will be subsequently adjusted to reflect the 2016 impact of the OEB's multi-year demand side management decision and order. The Company received its multi-year demand side management decision from the OEB in January 2016. The Company is evaluating the rate impact and will file with the OEB in the first quarter of 2016 an accounting order to implement final 2016 rates.

2015 RATE APPLICATION

The Company's final rate order for the setting of rates for 2015 was approved by the OEB in May 2015. The 2015 application was filed in accordance with the Company's approved customized IR plan, and represents the second year of a five-year term.

EQUITY INJECTION BY PARENT COMPANY

In November 2015, the Company's parent company subscribed for and was issued an additional 11,092,624 common shares for proceeds of $200 million, which supported the Company's growth initiatives.

GTA PROJECT

The Company is undertaking the expansion of its natural gas distribution system in the GTA to meet the demands of growth and to 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 (Western segment) and a 23-kilometre 36-inch diameter pipeline (Eastern segment) that are both expected to be in service by the end of the first quarter of 2016, as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in the GTA. The project is expected to cost approximately $930 million, an increase of approximately $175 million since December 31, 2014 as a result of greater complexity in the construction and requirements from government and permitting agencies. Expenditures up to December 31, 2015 are approximately $750 million.

FRANKLIN COUNTY EXPANSION PROJECT

In July 2012, St. Lawrence 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 high pressure distribution line was completed in July 2015. The total capital cost through 2018, including several distribution systems, is estimated to be US$52 million, with expenditures up to December 31, 2015 of approximately US$51 million. The build out of the distribution infrastructure will continue for several years and has the potential to increase St. Lawrence's customer base by 4,400 customers, an increase of approximately 28% from pre-project levels.

PRECEDENT AGREEMENTS FOR LONG-TERM TRANSPORTATION CAPACITY

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 Limited Partnership'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. In December 2015 the OEB approved the cost consequences of the transportation agreement through its approval of the Company's application for pre-approval of the cost consequences of long-term natural gas transportation contract for capacity on the NEXUS Pipeline.

In March 2015, the Company signed precedent agreements and financial assurance agreements with TransCanada Pipelines Limited (TransCanada) for the conversion of certain existing contracted long-haul transportation capacity (from Empress, Alberta to the Company's franchise areas) to short-haul transportation capacity (from Parkway (GTA) to the Company's franchise areas). Concurrently, the Company signed precedent agreements and financial assurance agreements with TransCanada for incremental pipeline transportation capacity from Parkway (GTA) to the Company's franchise areas. In May 2015, the Company signed a precedent agreement and a financial backstopping agreement with Union Gas Limited (Union) for pipeline transportation capacity from the Dawn trading hub to Parkway (GTA). All related transportation agreements will have a 15-year term and are targeted to start in November 2017. The agreements are required to meet growth in customer demand and to allow the transition of a portion of the Company's natural gas transportation capacity portfolio from long-haul to short-haul transportation made possible by the September 2013 TransCanada Mainline Settlement Agreement signed between the Company, TransCanada, Union and Gaz Métro Limited Partnership.

RESULTS OF OPERATIONS

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Gas commodity and distribution revenue	**3,043**	2,803	2,221
Transportation of gas for customers	**344**	305	328
Gas commodity and distribution costs	**(2,322)**	(2,046)	(1,480)
Gas distribution margin[1]	**1,065**	1,062	1,069
Other revenue	**97**	92	97
Operating and administrative expenses	**(509)**	(493)	(496)
Depreciation and amortization	**(290)**	(286)	(304)
Earnings sharing	**(7)**	(12)	-
Other income	**70**	66	65
Interest expense, net	**(181)**	(177)	(171)
Income taxes	**(11)**	(6)	(43)
Earnings	**234**	246	217
Earnings attributable to the common shareholder	**232**	244	215

1 For more information on this non-GAAP measure see page 2.

GAS DISTRIBUTION MARGIN

The heating degree days reported in 2015 were 174 heating degree days colder compared with forecast heating degree days. On a weather-normalized basis, gas distribution margin for the year ended December 31, 2015 would have been lower by $15 million (2014 - lower by $48 million). Weather, measured in heating degree days, was 3,710 heating degree days for the year ended December 31, 2015 compared with 4,044 heating degree days for the year ended December 31, 2014.

Gas distribution margin for the year ended December 31, 2015 increased by $3 million compared with the year ended December 31, 2014. The increase was primarily due to higher distribution charges and customer growth. This was partially offset by warmer weather in 2015 compared with 2014 and the settlement of regulatory balances.

The heating degree days reported in 2014 were 527 heating degree days colder compared with forecast heating degree days. On a weather-normalized basis, 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, 2014 decreased by $7 million compared with the year ended December 31, 2013. The decrease was primarily due to lower distribution charges partially offset by colder weather and customer growth.

OTHER REVENUE

Other revenue for the year ended December 31, 2015 increased by $5 million compared with the year ended December 31, 2014. The increase was primarily due to higher DSMIDA revenue and higher pipeline and storage optimization sales.

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.

OPERATING AND ADMINISTRATIVE

Operating and administrative expenses for the year ended December 31, 2015 increased by $16 million compared with the year ended December 31, 2014. The increase was primarily due to higher employee severance costs, partially offset by the settlement of regulatory balances.

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 the settlement of regulatory balances.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the year ended December 31, 2015 increased by $4 million compared with the year ended December 31, 2014. The increase primarily resulted from a higher overall asset base resulting from customer growth projects and improvements to the distribution system.

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.

EARNINGS SHARING

Under the customized IR plan, earnings sharing represents the estimated customer portion of regulated normalized earnings in excess of the approved return on equity (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 earnings sharing will result in the return of revenue of $7 million to customers for the year ended December 31, 2015, subject to OEB approval, compared to $12 million for the same period in 2014. Earnings sharing did not apply to the 2013 rate year.

OTHER INCOME

Other income for the year ended December 31, 2015 increased by $4 million compared with the year ended December 31, 2014. The increase primarily resulted from a gain on sale of assets.

Other income for the year ended December 31, 2014 and 2013 was relatively consistent.

INTEREST EXPENSE

Interest expense, net, for the year ended December 31, 2015 increased by $4 million compared with the year ended December 31, 2014. The increase was primarily due to the issuance of medium-term notes (MTNs) in 2015, lower interest earned on regulatory deferrals and a loss on settlement of pre-issuance hedge contracts. This was partially offset by higher capitalized interest.

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 MTNs in 2014 and additional draws on the credit facilities at a higher interest rate. This was partially offset by higher interest earned on regulatory deferrals.

INCOME TAXES

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
Earnings before income taxes	**245**	252	260
Income taxes	**11**	6	43
Effective tax rate (%)	**4.5**	2.4	16.5

The effective tax rate for the year ended December 31, 2015 was higher compared with the year ended December 31, 2014. The increase was due to lower postretirement benefit contributions compared to 2014, temporary differences relating to regulatory property, plant and equipment and intangible assets. This was partially offset by lower pre-tax earnings.

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, and temporary differences relating to regulatory property, plant and equipment and intangible assets, and lower pre-tax earnings.

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).

Enbridge Gas Distribution
For the year ended December 31, 2015, Enbridge Gas Distribution's rates were set according to the OEB approved settlement agreement (April 2015) and final rate order (May 2015). The rates approved as part of the 2015 rate application represented the second year of the Company's customized IR plan, which set rates for the period of 2014 to 2018 and was approved by the OEB in 2014.

For the year ended December 31, 2014, Enbridge Gas Distribution's rates were set by the OEB's July 2014 decision, and subsequent August 2014 decision and rate order in the Company's customized IR application. The decisions and rate order established final 2014 allowed revenues and billing rates, as well as placeholder allowed revenues for 2015 through 2018. The customized IR plan requires Enbridge Gas Distribution to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates. The customized IR decision also approved the adoption a new approach for determining net negative salvage percentages as a component of the Company's depreciation rates in addition to the Company shares earnings above the approved base return, equally with customers.

Under the customized IR plan, the Company has continued 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 on a cost of service (COS) basis pursuant to an OEB approved settlement agreement.

St. Lawrence Gas
For the years ended December 31, 2015, 2014 and 2013, 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. 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.

During the years ended December 31, 2015, 2014 and 2013, the cost of natural gas was passed on to customers as a flow-through.

IMPACT OF RATE REGULATION
The Company follows U.S. GAAP, which may differ in its 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 2015 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 debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. The Company maintains a current MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. 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. If necessary, additional liquidity is available through intercompany transactions with its ultimate parent company, Enbridge, and other related entities. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2015. 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.

In June 2015, following Enbridge's announcement of the execution of the definitive agreement in connection with Enbridge's drop-down of Canadian liquids pipeline assets and certain Canadian renewable energy assets to Enbridge Income Fund, Standard & Poor's Ratings Services: (i) downgraded each of the Company's corporate credit rating and senior unsecured indebtedness credit rating from "A-" to "BBB+" and removed these ratings from credit watch; (ii) downgraded the Company's preference share credit rating from "P-2" to "P-2 (low)" and removed this rating from credit watch; and (iii) affirmed the Company's commercial paper credit rating of "A-1 (low)" and removed this rating from credit watch. DBRS Limited's ratings of the Company were not affected by the announcement.

All ratings now have a stable outlook and the Company believes that it continues to have appropriate access to financial markets.

In June 2015, the Company extended the term out date to May 2016 on its $300 million revolving credit facility from Enbridge, with a maturity date in May 2017.

In July 2015, the Company extended the term out date of its $1 billion external credit facility to July 2016, with a maturity date in July 2017.

In September 2015, the Company issued $400 million of 10-year MTNs at an interest rate of 3.31% and an additional $170 million of MTNs under the same terms as the August 2044 30-year MTN pricing supplement issued in August 2014 at an interest rate of 4.00%.

In December 2015, a new $1.5 billion shelf prospectus was filed as a continuation of the Company's MTN program, which was previously renewed in June 2014. The prospectus is effective for a 25-month period.

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, 2015.

				December 31, 2015	December 31, 2014
	Maturity dates	Total Facilities[1]	Draws[2]	Available	Total Facilities[1]
(millions of Canadian dollars)					
Enbridge Gas Distribution Inc.	2017	**1,300**	**595**	**705**	1,300
St. Lawrence Gas Company, Inc.	2019	**10**	**8**	**2**	8
Total credit facilities		**1,310**	**603**	**707**	1,308

1 *Includes a $300 million revolving credit facility from the Company's ultimate parent, Enbridge Inc. and matures in May 2017.*
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 also has $7 million (2014 - $6 million) of uncommitted demand credit facilities, of which $3 million (2014 - $2 million) was unutilized as at December 31, 2015.

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.

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 purchased gas cost variance (PGVA) account related to the Company's costs to supply gas to customers. 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, 2015, a PGVA balance of $129 million has been presented in Accounts receivable and other in the Consolidated Statements of Financial Position (2014 - $491 million), of which a portion relates to the 2014 increase in natural gas prices.

December 31,	**2015**	2014
(millions of Canadian dollars)		
Cash and cash equivalents	**36**	17
Accounts receivable and other	**790**	1,178
Due from affiliates	**10**	11
Gas inventories	**547**	563
Bank indebtedness	**(27)**	(9)
Short-term borrowings	**(599)**	(938)
Short-term borrowings from affiliates	**(40)**	(204)
Accounts payable and other	**(870)**	(861)
Due to affiliates	**(87)**	(95)
Current maturities of long-term debt	**(2)**	(2)
Working capital	**(242)**	(340)

Despite the negative working capital as at December 31, 2015, the Company has net available liquidity through access to funds from committed credit facilities, the issuance of MTNs in the Canadian public capital markets through the Company's current MTN shelf prospectus, and, if necessary, additional liquidity is available through related party transactions with Enbridge Inc. or other related entities. At December 31, 2015, the net available liquidity totaled $716 million (2014 - $198 million).

The Company must adhere to covenants in its credit facility agreements and Trust Indenture. Under the terms of the Company's Trust Indenture, in order to continue to issue long-term debt, the Company's pro forma long-term debt interest coverage ratio must be at least two times for twelve consecutive calendar months of the previous 23 months. As at December 31, 2015, the Company was in compliance with all covenants.

OPERATING ACTIVITIES

Cash provided by operating activities was $842 million for the year ended December 31, 2015 compared with cash used of $430 million in 2014. The increase in cash provided by operating activities primarily resulted from an increase in the amounts recovered from customers related to the PGVA.

Cash used by operating activities was $430 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 the 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.

INVESTING ACTIVITIES

Cash used for investing activities was $864 million for the year ended December 31, 2015 compared with $620 million in 2014. The increase in cash used was primarily due to higher comparative capital spend on the GTA Project, the Work and Asset Management Solution (WAMS) program, and improvements to the distribution system.

Cash used for investing activities was $620 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 the WAMS program.

CAPITAL EXPENDITURES

Year ended December 31,	**2015**	2014	2013
(millions of Canadian dollars)			
System improvements and upgrades	**751**	371	298
System expansion	**160**	165	167
Computers and communication equipment	**53**	44	39
Unregulated storage	**-**	1	1
Other	**59**	56	48
Total capital expenditures	**1,023**	637	553

The Company's existing distribution network consists of approximately 38,400 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 $700 million in 2016 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $634 million.

Major 2016 capital projects include the GTA Project and the WAMS 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 $41 million for the year ended December 31, 2015 compared with $1,034 million in 2014. The decrease in cash provided primarily resulted from higher net repayments on short-term borrowings. This was partially offset by higher net term note issuances and higher common shares issued.

Cash provided by financing activities was $1,034 million for the year ended December 31, 2014 compared with $126 million in 2013. The increase in cash provided primarily resulted from higher net issuance of short-term borrowings, partially offset by higher net repayments of term notes.

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, 2015, 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	170,076,674

1. Outstanding share data information is provided as at February 18, 2016.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the Consolidated Statements of Financial Position between December 31, 2014 and December 31, 2015.

Consolidated Statements of Financial Position Category	Increase/ (Decrease)	Explanation
(millions of Canadian dollars)		
Accounts receivable and other (including due from affiliates)	(389)	Primarily due to lower natural gas costs to be recovered from customers related to the PGVA within the next 12 months, and lower sales volume as a result of warmer weather leading to a reduction in the amount of receivables from customers.
Property, plant and equipment, net	813	Primarily due to capital additions relating to distribution system improvements, the WAMS program, and the GTA Project, partially offset by depreciation.
Deferred amounts and other assets	(182)	Primarily due to the amount of PGVA being recovered of nil for 2015 compared to $182 million for 2014.
Short-term borrowings (including amounts from affiliates)	(503)	Primarily due to lower working capital needs and repayments of short-term borrowings using cash and cash equivalents generated from operations.
Other long-term liabilities	(96)	Primarily due to lower long-term amounts expected to be refunded to customers through the site restoration clearance adjustment.
Long-term debt (including current portion)	556	Primarily due to the issuance of MTNs during the year.
Common shares	200	Due to a common share issuance during the year.

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, a former owner of part of the Historic Distillery District (Wyndham Court Canada Inc.) commenced an action in the Ontario Court of Justice (General Division) against the Company alleging that coal tar originating from the Company's Station A MGP in Toronto had migrated to its lands. The Company entered into a Tolling Agreement with Wyndham Court Canada Inc. pursuant to which this action was discontinued, without prejudice to the right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham Court Canada Inc. 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 2015 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	1-2 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt[1]	3,688	2	504	402	2,780
Gas transportation and storage contracts[2]	5,171	1,162	1,388	970	1,651
Loans from affiliate company[1]	375	-	-	-	375
Customer care service contracts	225	54	113	58	-
Right-of-way commitments[3]	130	2	4	4	120
Capital commitments	192	132	32	21	7
Operating leases	4	4	-	-	-
Pension obligations[4]	4	4	-	-	-
Total contractual obligations	9,789	1,360	2,041	1,455	4,933

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 March 2015 and May 2015.*
3. *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.*
4. *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.*

The Company, Enbridge, and Enbridge Pipeline Inc., in aggregate, have access to $95 million of letters of credit that they can issue, of which $37 million was unutilized as of December 31, 2015. The total outstanding letters of credit that related to the Company as of December 31, 2015 was $5 million. The Company had access to $75 million of letters of credit that it could issue, of which $51 million was unutilized as of December 31, 2014. The total outstanding letters of credit that related to the Company as of December 31, 2014 was $24 million.

QUARTERLY FINANCIAL INFORMATION[1]

	2015				2014			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
(millions of Canadian dollars)								
Revenues	**769**	**372**	**609**	**1,734**	928	362	672	1,238
Earnings attributable to the common shareholder[2]	**41**	**12**	**48**	**131**	72	5	29	138
(Colder)/warmer than normal weather (after-tax impact)	**16**	**-**	**6**	**(33)**	(1)	2	(4)	(33)
Loss on settlement of pre-issuance hedge contracts	**-**	**3**	**-**	**-**	-	-	-	-

1. *Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2. *Earnings per share is not provided, since the Company is an indirect wholly owned subsidiary of Enbridge.*

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.

FOURTH QUARTER 2015 HIGHLIGHTS

Earnings attributable to the common shareholder were $41 million for the three months ended December 31, 2015 compared with $72 million for the same period in 2014. The decrease was primarily due to warmer weather during the fourth quarter of 2015 compared to 2014, higher employee severance costs, higher income taxes resulting from the timing of lower postretirement benefit contributions, and higher operating and administrative costs resulting from the timing of costs incurred on the demand side management program.

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 a higher after-tax rate of return on common equity reflected in rates.

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 monthly 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, 2015, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2015, dividends received amounted to $63 million (2014 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2015 (2014 - $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, 2015, interest paid amounted to $27 million (2014 - $27 million) with an outstanding payable balance of $2 million at December 31, 2015 (2014 - $2 million).

Enbridge (U.S.), an affiliated company under common control, advanced St. Lawrence $40 million (2014 - $29 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, 2015 were $50 million (2014 - $41 million) with an outstanding payable balance of $4 million at December 31, 2015 (2014 - $7 million).

Enbridge Inc., established a $300 million revolving credit facility with the Company in June 2014, which has a term out date in May 2016 and a maturity date in May 2017. For the year ended December 31, 2015, nil (2014 - $175 million) was drawn, and interest paid amounted to nil (2014 - $2 million) with an outstanding payable balance of nil at December 31, 2015 (2014 - 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, 2015 were $23 million (2014 - $41 million) with an outstanding payable balance of nil at December 31, 2015 (2014 - $3 million).

Tidal Energy Marketing Inc., an affiliated company under common control, obtains optimization services from the Company. Total revenues for the year ended December 31, 2015 were $7 million (2014 - $7 million) with an outstanding receivable balance of nil at December 31, 2015 (2014 - nil).

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, 2015 were $24 million (2014 - $57 million) with an outstanding payable balance of $4 million at December 31, 2015 (2014 - $3 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, 2015 were $62 million (2014 - $16 million) with an outstanding payable of $2 million at December 31, 2015 (2014 - $8 million).

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, 2015 were $40 million (2014 - $31 million) with an outstanding receivable of $3 million at December 31, 2015 (2014 - $6 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, 2015 were $28 million (2014 - $27 million) with an outstanding payable of $1 million at December 31, 2015 (2014 - $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, 2015 were $2 million (2014 - $2 million) with an outstanding payable of nil at December 31, 2015 (2014 - 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, 2015 were $28 million (2014 - $26 million) with an outstanding payable of $2 million at December 31, 2015 (2014 - $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, 2015 were $22 million (2014 - $20 million) with an outstanding payable of $2 million at December 31, 2015 (2014 - $2 million).

Niagara Gas Transmission Limited, an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2015 were $2 million (2014 - $2 million) with an outstanding payable of nil at December 31, 2015 (2014 - nil).

Other Transactions

The Company provides consulting and other shared corporate services to affiliates on a fully-allocated cost basis. Market prices, if they are reasonably determinable, are charged for affiliate services that are not shared corporate services. 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, 2015, the Company had an outstanding payable of nil to Enbridge Pipelines Inc. (2014 - $15 million receivable) and an outstanding payable of $13 million to Enbridge Employee Services Inc. (2014 – nil).

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, intervenors and regulators to help minimize regulatory risk. The strong regulatory relationship continued in 2015 as the Company's filed 2015 and 2016 rate applications were approved by the OEB through settlement agreements rather than litigation. Under the customized IR decision, the Company does not file a request with the OEB to set its annual ROE. The OEB sets through its formulaic process the allowed ROE that the Company is permitted to charge in rates, 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, 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, and for the establishment of rate riders required to refund or collect gas cost variances. Adjustments are subject to OEB approval. St. Lawrence monitors its gas cost variance balance, and its potential impact on customers, and can request interim rate relief that will allow it to recover or refund the natural gas cost differential.

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	2.2 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 80% (2014 - 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.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates.

The Company generates certain revenues, and holds a subsidiary that is denominated in a currency other than Canadian dollars. As a result, the Company's earnings and cash flows are exposed to fluctuations resulting from foreign exchange rate variability.

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 against the effect of future interest rate movements 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 variations in interest rates on certain long-term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk. Additional information about the Company's derivative instruments is included in Note 16 of the 2015 annual Consolidated Financial Statements.

The Company's portfolio mix of fixed and variable rate debt instruments is monitored by its ultimate parent company, Enbridge Inc. The Company does not typically manage the fair value of its debt instruments.

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.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments as they become due. 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 or draws under committed credit facilities, and issuance of 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 MTN shelf prospectus with securities regulators, which enables ready access to the Canadian public capital markets, subject to market conditions. 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, 2015. 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.

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 indebtedness, 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, 2015 the fair value of the investment was $825 million (2014 - $825 million), which approximates its cost and redemption value. At December 31, 2015, the Company's long-term debt had a carrying value of $3,683 million (2014 - $3,127 million) and a fair value of $4,159 million (2014 - $3,709 million).

Additional information about the Company's risk management and financial instruments is included in Note 16 of the 2015 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.

Operating Risk

The Company's network, including storage assets are exposed to operational risks such as accidental damage to mains and service lines, corrosion 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 are an inherent risk of operations. Surveillance, maintenance and repair programs as well as the phased replacement of targeted pipes and facilities significantly reduces the exposure. In 2012, the Company completed its cast iron replacement and bare steel main replacement programs.

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 and storage operations. The occurrence or continuance of any of these events could increase the operating costs or reduce revenues, thereby impacting earnings.

The Company has extensive programs to manage pipeline and storage well integrity, which include leak survey, corrosion survey and the use of in-line inspection tools for high stress pipelines. Maintenance and inspection programs are directed to the areas of greatest benefit and pipe and facilities are replaced or repaired as the need is identified. The Company also maintains comprehensive insurance coverage for significant 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.

Project Execution
The ability to successfully complete significant projects may be influenced by capital constraints, third party opposition, delays in or changes to government and regulatory approvals, cost escalations, construction delays, inadequate resources, in-service delays and increasing complexity of projects. On certain of its projects, the Company does not have protection against recovery of cost overruns and the associated return during its current regulatory term, which means that any cost overruns on such projects may be funded by the Company. For projects related to its regulated operations, the Company does have an opportunity to seek recovery of future costs at designated future dates based on the regulatory framework. Cost escalations or missed in-service dates on future projects may impact future earnings and customer base. Construction delays due to regulatory delays, contractor or supplier non-performance and weather conditions may impact project development.

Environmental, Health and Safety Risk
The Company’s operations and facilities are subject to national, regional and local environmental, health and safety laws which regulate the protection of the environment and the health and safety of workers. From an environmental perspective, this includes regulating discharges to air, land and water; handling and storage of petroleum compounds and hazardous wastes; solid and hazardous waste management and disposal; and the assessment of contaminated sites.

There is the risk that by operating its gas distribution system and storage operations, the Company could experience incidents, malfunctions or other unplanned events that could result in spills or emissions to the environment exceeding permitted levels. There is risk that this could result in injuries to workers or the public, fines, penalties or other sanctions and/or property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties.

The gas distribution system must maintain a number of environmental and other permits from various governmental authorities in order to operate. As a result, these facilities and the distribution network are subject to periodic inspection. Failure to maintain regulatory compliance could result in operational interruptions, fines, penalties, and/or orders for additional pollution control technology, environmental remediation, etc. As environmental requirements and regulations become more stringent, the cost to maintain compliance and the time to obtain approvals will increase.

In early 2015, Ontario announced its intention to develop a cap and trade carbon system that will be linked with Quebec and California. In December 2015, the Ontario greenhouse gas (GHG) reporting regulation was amended to include additional sources, including emissions resulting from the distribution of natural gas and equipment used for natural gas transmission, distribution and storage. Ontario continues to work on drafting the cap and trade regulation, which is expected in the second quarter of 2016. Implementation of cap and trade is expected as early as January 1, 2017. Under the cap and trade regulation, the Company will be required to purchase emission allowances for its customers. The recent amendments in Ontario to GHG regulations and the upcoming implementation of a cap and trade carbon system could require a significant response from the Company. Environmental non-compliance or significant costs to maintain compliance could have an impact on the demand for the Company's product affecting operating results and profitability. There is also the potential for the Company to be targeted by environmental groups attempting to draw attention to the generation of GHG emissions.

In 2015, the Company was required to report GHG emissions to the Ontario Ministry of Environmental and Climate Change from combustion sources only in Ontario, and all reported data was verified by a third party. There were no issues identified for the 2015 reporting year. The Company monitors developments and attend Stakeholder consultations in Ontario.

The Company utilizes 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.

The Company participates in the comprehensive insurance program which is maintained by Enbridge for its subsidiaries and affiliates. The insurance program includes coverage for commercial general liability that is considered customary for its industry and includes coverage for sudden and accidental pollution incidents. In the unlikely event that multiple insurable incidents exceeding the program 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 efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its operational risk management plan, emergency response preparedness, and continued improvements of safety and operating systems. 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.

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. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to development projects. 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 treat 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;
- building awareness and understanding of the role energy and Enbridge play in people's lives in order to shape public perception of the Company;
- having strong corporate governance practices, including a Statement on Business Conduct, which requires all employees to certify their compliance with the Company policy 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 Enbridge's Corporate Social Responsibility Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative).

The actions noted above are the key mitigation action against negative public opinion; however, the public opinion risk cannot 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 and intellectual property. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems which could impact operations and potentially result in an environmental or public safety incident. 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 which could have lasting reputational impact to the Company and could impact its ability to work with various stakeholders.

The Company has implemented a comprehensive security strategy that includes a security policy and standards framework, defined governance and oversight, layered access controls, continuous monitoring, infrastructure and network security, and threat detection and incident response through a security operations centre. The Company's information technology security operations are consolidated under one Enbridge-wide 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, 2015 of $7,081 million (2014 - $6,268 million), or 71% of total assets (2014 - 64%), 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, 2015, the Company's regulatory assets totaled $742 million (2014 - $1,278 million) and regulatory liabilities totaled $806 million (2014 - $973 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 actual return on plan assets was $14 million lower than the expected return on plan assets for the year ended December 31, 2015 (2014 - $38 million higher) as disclosed in Note 18 to the 2015 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, contributions in 2016 will be $4 million.

The following sensitivity analysis identifies the impact on the December 31, 2015 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	74	7	8	-
Decrease in expected return on assets	-	5	n/a	n/a
Decrease in rate of salary increase	(12)	(3)	-	-

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 22 of the 2015 annual Consolidated Financial Statements.

REGULATORY GOVERNANCE

Undertakings

The Company, and its ultimate 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, Open Bill 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.

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

FUTURE ACCOUNTING POLICY CHANGES

Measurement Date of Defined Benefit Obligation and Plan Assets

Accounting Standards Update (ASU) 2015-04 was issued in April 2015 with the intent to simplify the fair value measurement of defined benefit plan assets and obligations. Where there are significant events in an interim period that would trigger a re-measurement of the plan assets and obligations, an entity is permitted to re-measure such assets and obligations using the month end that is closest to the date of the significant event. The accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs

ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires a debt issuance cost related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. Further, ASU 2015-15 was issued in August 2015 to clarify the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements, whereby the Company may defer debt issuance costs as an asset and subsequently amortize them over the term of the line-of-credit. The accounting updates are effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's 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. In July 2015, the effective date of the new standard was delayed by one year and the new standard is now effective for annual and interim periods beginning on or after December 15, 2017 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.

Classification of Deferred Taxes on the Statement of Financial Position

ASU 2015-17 was issued in November 2015 with the intent to simplify the presentation of deferred income taxes. The amendments eliminate the current requirement to present deferred tax asset and liabilities as current and noncurrent. The amendments require that all deferred tax assets and liabilities be classified as noncurrent in a classified statement of financial position. The accounting update is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years and is to be applied on a prospective basis. Early application is permitted for all entities as of the beginning of an interim or annual reporting period. Effective January 1, 2016, the Company will elect to early adopt ASU 2015-17. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Recognition and Measurement of Financial Assets and Liabilities

ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the consolidated Statement of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively. The Company is currently assessing the impact of the new standard on its consolidated financial statements.

Simplifying the Measurement of Inventory

ASU 2015-11 was issued in July 2015 with the intent to simplify the measurement of inventory. The new standard requires inventory to be measured at the lower of cost and net realizable value and is applicable to all inventory, with the exception of inventory measured using last-in, first-out or the retail inventory method. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim reporting periods beginning after December 15, 2016 and is to be applied on a prospective basis

CHANGES IN ACCOUNTING POLICY

Book Overdrafts

Prior to January 2015, the Company recorded all obligations for which cheques were issued but not presented to the financial institution in Accounts payable and other. Effective January 2015, the Company changed the accounting policy and began presenting only book overdrafts in Accounts payable and other. Comparative figures presented in the audited consolidated financial statements for the year ended December 31, 2015 have been retrospectively revised. The change in accounting policy did not have a material impact on the audited Consolidated Statements of Financial Position and audited Consolidated Statements of Cash Flows for previously issued financial statements. There was no impact to the audited Consolidated Statement of Earnings. The change in accounting policy allows for the Company to account for its book overdrafts in a preferable method.