Lorraine Chiasson
Regulatory Coordinator
Regulatory Affairs

tel 416 495 5499
egdregulatoryproceedings@enbridge.com

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

June 27, 2018

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")
2017 Earnings Sharing Mechanism and Other Deferral And Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2018-0131

Enclosed please find Enbridge Gas Distribution's Application and supporting evidence for an order approving the clearance or disposition of amounts recorded within its 2017 Earnings Sharing Mechanism Deferral Account and within certain other deferral or variance accounts.

The Application has been filed through the Board's Regulatory Electronic Submission System and will be available on the Enbridge website at: www.enbridgegas.com/ratecase.

Please contact the undersigned if you have any questions.

Yours truly,

[original signed]

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. D. Stevens, Aird & Berlis LLP
All Interested Parties EB-2017-0102 (via email)

EXHIBIT LIST

A – ADMINISTRATIVE

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

B – 2017 ACTUAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	1	1	2017 Earnings Sharing Amount and Determination Process	R. Small
		2	ESM Calculations and Required Rate of Return 2017 Actuals	R. Small
		3	2017 Utility Earnings – Contributors to Utility Earnings and Earnings Sharing Amounts	R. Small
		4	Utility Earnings – Reconciliation of 2017 Utility Income to Audited EGDI Consolidated Income	R. Small
	2	1	Ontario Utility Rate Base – Comparison of 2017 Actuals to 2017 EB-2016-0215 Board Approved	R. Small
		2	Property, Plant and Equipment Summary Statement – Average of Monthly Averages 2017 Actuals	R. Small

EXHIBIT LIST

B – 2017 ACTUAL YEAR & EARNINGS SHARING RESULTS

Exhibit	Tab	Schedule	Contents	Witness(es)
B	2	3	Working Capital – 2017 Actuals	R. Small
		4	Comparison of Utility Capital Expenditures 2017 Actuals and 2017 EB-2016-0215 Board Approved	S. Riccio
	3	1	Utility Operating Revenue 2017 Actuals	R. Small
		2	Comparison of Gas Sales and Transportation Volume by Rate Class 2017 Actuals to 2017 EB-2016-0215 Board Approved	R. Cheung J. Shem
		3	Comparison of Gas Sales and Transportation Revenue by Rate Class 2017 Actuals to 2017 EB-2016-0215 Board Approved	R. Cheung
		4	Customers Meters, Volumes and Revenues by Rate Class 2017 Actuals	R. Cheung
		5	2017 Other Operating Revenue	E. Chang L. Wigelius
	4	1	Operating Cost 2017 Actuals	R. Small
		2	Operating and Maintenance Expense by Category Year Ending December 31, 2017	S. Fallis
	5	1	Required Rate of Return 2017 Actuals	R. Small
		2	Utility Income 2017 Actuals	R. Small
		3	Cost of Capital 2017 Actuals	R. Small

EXHIBIT LIST

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	1	Balances Requested for Clearance at January 1, 2019	R. Small
		2	2017 Storage & Transportation Deferral Account and 2017 Transactional Services Deferral Account	K. Lakatos-Hayward D. Small
		3	2017 Unaccounted For Variance Account	K. Lakatos-Hayward J. Shem
		4	2017 Actual Average Use True Up Variance Account	R. Cheung M. Suarez
		5	2017 Post Retirement True Up Variance Account	R. Rutitis C. Tuckwell
		6	2017 Gas Distribution Access Rule Impact Deferral Account	D. McIlwraith R. Small
		7	2017 Deferred Rebate Account	R. Small
		8	2017 Transition Impact of Accounting Changes Deferral Account	R. Small C. Tuckwell
		9	2017 Customer Care CIS Rate Smoothing Deferral Account	D. McIlwraith R. Small
		10	2017 Electric Program Earnings Sharing Deferral Account	J. Tideman
		11	2017 Ontario Energy Board Cost Assessment Variance Account	R. Small

EXHIBIT LIST

C– EARNINGS SHARING MECHANISM and OTHER DEFERRAL & VARIANCE ACCOUNTS

Exhibit	Tab	Schedule	Contents	Witness(es)
C	1	12	2018 Constant Dollar Net Salvage Adjustment Deferral Account	R. Small A. Kacicnik
		13	2017 Dawn Access Costs Deferral Account	R. DiMaria R. Small
	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	R. Torul
		2	Status of System Integrity Program	D. Broude
		3	Status of Benchmarking Study	R. Torul
		4	Status of Asset Management Planning Process	H. Thompson
	2	1	Productivity Initiatives Summary	M. Suarez
	3	1	June 6, 2018 Stakeholder Day Presentation	R. Torul
	4	1	2017 RRR filings re. Service Quality Indicators	D. Brault D. McIlwraith

EXHIBIT LIST

D – REPORTING AND REFERENCE MATERIAL

Exhibit	Tab	Schedule	Contents	Witness(es)
D	5	1	Enbridge Gas Distribution Inc. Consolidated Financial Statements December 31, 2017	C. Tuckwell
		2	Enbridge Gas Distribution Inc. Management's Discussion & Analysis December 31, 2017	C. Tuckwell

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

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

A P P L I C A T I O N

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

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

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

4. Under the Custom IR framework, after the release of its Audited Financial Statements for the prior year Enbridge is required to file an Application setting out the ESM calculation for that year. Within the Application, Enbridge is to set out its proposal for the clearance of amounts recorded in the Earnings Sharing Mechanism Deferral Account ("ESMDA") and other Deferral and Variance Accounts.

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

6. In this Application, Enbridge seeks approval to clear the balance of the 2017 ESMDA, as well as the balances within certain of its 2017 Deferral and Variance accounts and the 2018 Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA") and the 2018 Transactional Impact of Accounting Changes Deferral Account ("TIACDA"). Enbridge also seeks approval to carry forward the balances in certain Deferral and Variance 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 2017 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 January 1, 2019 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
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: June 27, 2018 at Toronto, Ontario.

ENBRIDGE GAS DISTRIBUTION INC.

Per: [original signed]

Andrew Mandyam

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at May 31, 2018 Principal ($000's)	Col. 2 Actual at May 31, 2018 Interest ($000's)	Col. 3 Forecast for clearance at January 1, 2019 Principal ($000's)	Col. 4 Forecast for clearance at January 1, 2019 Interest ($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Managment V/A	2017 DSMVA	(1,277.1)	(8.8)	-	-	[1]
2.	Demand Side Managment V/A	2016 DSMVA	(704.0)	(13.3)	-	-	[1]
3.	Demand Side Managment V/A	2015 DSMVA	825.5	26.8	-	-	[1]
4.	Lost Revenue Adjustment Mechanism	2017 LRAM	-	-	-	-	[1]
5.	Lost Revenue Adjustment Mechanism	2016 LRAM	(100.0)	(0.7)	-	-	[1]
6.	Lost Revenue Adjustment Mechanism	2015 LRAM	(72.3)	(1.4)	-	-	[1]
7.	Demand Side Managment Incentive D/A	2016 DSMIDA	2,893.5	23.6	-	-	[1]
8.	Demand Side Managment Incentive D/A	2015 DSMIDA	6,068.6	120.3	-	-	[1]
9.	Deferred Rebate Account	2017 DRA	1,834.0	36.7	1,834.0	57.0	[2]
10.	Gas Distribution Access Rule Impact D/A	2017 GDARIDA	-	-	265.9	-	[3]
11.	Manufactured Gas Plant D/A	2018 MGPDA	618.9	50.8	-	-	[4]
12.	Electric Program Earnings Sharing D/A	2017 EPESDA	(680.2)	(4.7)	(680.2)	(12.4)	[5]
13.	Average Use True-Up V/A	2017 AUTUVA	(4,035.7)	(27.8)	(4,035.7)	(72.6)	[6]
14.	Earnings Sharing Mechanism Deferral Account	2017 ESMDA	(23,700.0)	(163.5)	(23,550.0)	(423.4)	[7]
15.	Customer Care CIS Rate Smoothing D/A	2017 CCCISRSDA	(2,785.3)	(35.8)	-	(59.6)	[8]
16.	Customer Care CIS Rate Smoothing D/A	2016 CCCISRSDA	(779.9)	(7.6)	-	(14.6)	[8]
17.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	11.0	-	20.8	[8]
18.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	28.7	-	53.9	[8]
19.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	45.4	-	85.3	[8]
20.	Transition Impact of Accounting Changes D/A	2018 TIACDA	66,537.0	-	4,435.8	-	[9]
21.	Post-Retirement True-Up V/A	2017 PTUVA	(4,299.2)	(47.1)	(4,299.2)	(94.7)	[10]
22.	Constant Dollar Net Salvage Adjustment D/A	2018 CDNSADA	18,910.1	-	6,468.3	-	[11]
23.	Greenhouse Gas Emissions Impact D/A	2016 GGEIDA	939.8	22.1	-	-	[12]
24.	Greenhouse Gas Emissions Impact D/A	2017 GGEIDA	2,176.1	27.6	-	-	[12]
25.	OEB Cost Assessment V/A	2017 OEBCAVA	2,649.9	35.2	2,649.9	64.6	[13]
26.	Greenhouse Gas Emissions Compliance Obligation-Customer Related V/A	2017 GGECOCRVA	11,471.8	156.2	-	-	[12]
27.	Dawn Access Costs D/A	2017 DACDA	-	-	(910.7)	-	[14]
28.	Total non commodity Related Accounts		85,177.6	273.7	(17,821.9)	(395.7)	
	Commodity Related Accounts						
29.	Transactional Services D/A	2017 TSDA	1,206.4	7.5	1,206.4	20.8	[15]
30.	Storage and Transportation D/A	2017 S&TDA	22,654.8	280.3	22,654.8	530.2	[15]
31.	Unaccounted for Gas V/A	2017 UAFVA	(1,129.9)	(21.9)	(1,129.9)	(34.5)	[16]
32.	Total commodity related accounts		22,731.3	265.9	22,731.3	516.5	
33.	Total Deferral and Variance Accounts		107,908.9	539.6	4,909.4	120.8	

Notes:

1. The clearance of DSM related accounts will be determined through separate DSM proceedings.
2. DRA evidence is found at Exhibit C, Tab 1, Schedule 7.
3. The clearance amount associated with the 2017 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 6.
4. Clearance of the balance that was recorded in 2017 MGPDA is not being requested at this time. As was approved in the EB-2017-0086 proceeding, the balance in the 2017 MGPDA was transferred to the 2018 MGPDA.
5. EPESDA evidence is found at Exhibit C, Tab 1, Schedule 10.
6. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 4.
7. Evidence within the B-series of exhibits provides details of Enbridge's 2017 utility results and 2017 earnings sharing calculation.
8. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 9.
9. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 8.
10. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
11. CDNSADA evidence is found at Exhibit C, Tab 1, Schedule 12 and Exhibit C, Tab 2, Schedule 1.
12. Clearance of Cap and Trade related accounts (GGEIDA, GGECOCRVA, & GGECOFRVA) will be determined through Cap and Trade compliance plan proceedings.
13. OEBCAVA evidence is found at Exhibit C, Tab 1, Schedule 11.
14. DACDA evidence is found at Exhibit C, Tab 1, Schedule 13 and Exhibit C, Tab 2, Schedule 1.
15. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 2.
16. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 3.

OVERVIEW AND APPROVALS REQUESTED

1. This proceeding addresses Enbridge's request for clearance of the balances in its 2017 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
R. Torul

6. The B-series of exhibits sets out Enbridge's utility financial results for 2017, 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 2018 Custom IR Stakeholder Day, which was held on June 6, 2018. Other evidence includes the Company's 2017 Productivity Initiatives Reporting, Status Updates on several major projects and initiatives and the Company's 2017 Service Quality Indicators results. The Company's 2018 Gas Supply Memorandum was previously filed in the 2018 Rate Proceeding, EB-2017-0086. As was the case in Enbridge's 2016 ESM proceeding (EB-2017-0102), 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 2017 ESMDA and certain other Deferral and Variance Accounts.

10. The Company has filed the balances at May 31, 2018 for fiscal year 2017 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 January 1, 2018, 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 November 1, 2018, in order to facilitate the clearance of the Deferral and Variance Accounts through a rate rider by specific rate classes within the Company's January 1, 2019 QRAM proceeding.

Witnesses: R. Small
R. Torul

DRAFT ISSUES LIST

1. Is the amount proposed to be cleared in the 2017 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?

Witnesses: R. Small
R. Torul

CURRICULUM VITAE OF
DEBORAH BRAULT

Experience: Enbridge Gas Distribution Inc.

Customer Safety & Compliance Manager, Eastern Region
2015

Operations Manager, Gazifère Inc.
2010

WMC Manager, Eastern Region
2004

Operations Support Supervisor
1999

Call Centre Supervisor
1993

Customer Service Assistant Supervisor
1990

Customer Service Clerk
1986

Education: University of Ottawa

Memberships: None

Appearances: (Ontario Energy Board)

EB-2017-0102

CURRICULUM VITAE OF
DEIRDRE BROUDE, P.Eng

Experience: Enbridge Gas Distribution Inc.

Manager, Asset Management - Distribution and Storage
2018

Manager, Asset Classes, Asset Management
2016

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-2017-0102
EB-2012-0459
RP-2004-0015 (Leave to Construct)

CURRICULUM VITAE OF
ELENA CHANG

Experience: Enbridge Gas Distribution Inc.

Manager, Utility & Power Operational Accounting
2018

Supervisor, Gas Accounting
2014

Supervisor, Financial Reporting
2012

Senior Advisor, External Reporting & Pension
2010

Education: Master of Accounting, University of Waterloo (2008)

Bachelor of Accounting & Financial Management, University of Waterloo (2007)

Memberships: Chartered Professional Accountant (Ontario)

Appearances: (Ontario Energy Board)

None

CURRICULUM VITAE OF
RYAN CHEUNG

Experience:	Enbridge Gas Distribution Inc.
	Senior 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-2017-0086 EB-2017-0102 EB-2016-0215 EB-2016-0142 EB-2015-0122 EB-2015-0114 EB-2014-0195 EB-2012-0459

CURRICULUM VITAE OF
JACKIE E. COLLIER

Experience:

Enbridge Gas Distribution Inc.
Rate Design Specialist
2016

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-2017-0102
EB-2017-0086
EB-2016-0215
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-4003-2017	
R-3969-2016	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
ROB DiMARIA

Experience: Enbridge Gas Distribution Inc.

Manager, Large Volume Customer Strategy
2014

Manager, Key Accounts and Vendor Relationships
2009

Account Executive
2006

Senior Marketing Specialist
2003

Residential Program Manager
2001

Senior Analyst, Planning and Evaluation
2000

Rate Research Analyst
1998

Plant Accounting Chief Clerk
1994

Accounting Trainee
1992

Education: Bachelor of Administration, Business Management, Athabasca University
Diploma in Accounting and Financial Management, Centennial College

Appearances: (Ontario Energy Board)
EB-2017-0086
EB-2016-0215
EB-2014-0323
EB-2001-0032

CURRICULUM VITAE OF
SAM FALLIS

Experience: Enbridge Gas Distribution Inc.

Manager O&M Financial Management – Operational Finance
2018

Supervisor Capital Management – Operational Finance
2016

Finance Capital Lead – Operational Finance
2016

Finance O&M Lead – Operational Finance
2014

Senior Finance Analyst – Operational Finance
2013

City of Toronto

Senior Financial Planning Analyst – Financial Planning – FPARS
2012

Budget Analyst - Facilities Management - Business Support
2008

TMMS Analyst - Transportation Division
2007

Accounting Specialist - Facilities Management – Business Support
2006

Education: Master of Business Administration, with CPA, CMA Designation
Schulich School of Business – York University
2008 – 2011

Honors, Bachelor of Management & Organizational Studies –
Finance and Administration - University of Western Ontario
2002 – 2006

Appearances: (Ontario Energy Board)

None

CURRICULUM VITAE OF
ANTON KACICNIK

Experience: Enbridge Gas Distribution Inc.

Manager Rates
2016

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-2017-0306	
EB-2017-0224	
EB-2017-0086	
EB-2017-0102	EB-2016-0300
EB-2016-0142	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-4003-2017	
R-3969-2016	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
KERRY LAKATOS-HAYWARD

Experience: Enbridge Gas Distribution

Director, Energy Supply & Gas Storage
2016

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
New York Institute of Finance, 2014

LEAD 3 Executive Development Program,
Enbridge, 2016

Appearances: (Ontario Energy Board)

EB-2017-0102
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
DARREN MCILWRAITH

Experience: Enbridge Gas Distribution Inc.

Director, Customer Care
2016

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-2017-0102	EB-2016-0215
EB-2014-0276	EB-2016-0142
EB-2012-0459	EB-2015-0114

CURRICULUM VITAE OF
STEVEN RICCIO

Experience: Enbridge Gas Distribution Inc.

Supervisor, Capital Management
2017

Supervisor, Plant Accounting/Capital Assets
2016

Lead, Operations Capital
2014

Operations Reporting Analyst, Operations Capital
2013

Senior Analyst, Gas Accounting & Analytics
2010

Analyst, Revenue Accounting & Business Analytics
2008

Education: Bachelor of Commerce, Ryerson University, 2008

Memberships: N/A

Appearances: (Ontario Energy Board)

None

CURRICULUM VITAE OF
ROBERT RUTITIS

Experience: Enbridge Gas Distribution Inc.

Specialist, Accounting Operations
2017

Advisor, Financial Reporting
2016

Algonquin Power & Utilities Corp.

Senior Auditor, Internal Audit
2015

Union Gas Limited

Finance Analyst
2012

Education: Chartered Professional Accountant, Chartered Accountant (CPA, CA)
Chartered Professional Accountants of Ontario, 2015

Honours Bachelor of Business Administration
Wilfrid Laurier University, 2011

Memberships: Chartered Professional Accountants of Ontario

Appearances: (Ontario Energy Board)

None

CURRICULUM VITAE OF
JASON SHEM

Experience: Enbridge Gas Distribution Inc.

Supervisor, Gas Accounting
2016

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-2017-0102
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-2017-0102	EB-2017-0086
EB-2016-0215	EB-2008-0106
EB-2015-0114	EB-2006-0034
EB-2015-0122	EB-2005-0001
EB-2014-0276	RP-2003-0203
EB-2013-0046	RP-2003-0048
EB-2012-0459	RP-2002-0133
EB-2011-0354	RP-2001-0032
EB-2011-0277	RP-2000-0040
EB-2010-0146	RP-1999-0001
EB-2009-0172	EBRO 497
EB-2009-0055	EBRO 495
EB-2008-0219	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, Revenue and Regulatory Accounting 2016
	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-2017-0306/0307
EB-2017-0102
EB-2016-0215
EB-2015-0114
EB-2015-0122
EB-2014-0195
EB-2012-0055
EB-2011-0008
EB-2017-0086
EB-2016-0142
EB-2015-0049
EB-2014-0276
EB-2012-0459
EB-2011-0354

CURRICULUM VITAE OF
BRANDON SO

Experience:	Enbridge Gas Distribution Inc.
	Cost Allocation Specialist 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) EB-2017-0086 EB-2017-0102
	(RÉGIE DE L'ÉNERGIE) R-4003-2017 R-3969-2016

CURRICULUM VITAE OF
MARGARITA SUAREZ-SHARMA

Experience:	Enbridge Gas Distribution Inc.
	Manager, Economic Analysis & Business Performance 2014
	Manager, Economic & Market Analysis 2012
	Manager, Cost Allocation 2008
	Manager, DSM Reporting & Analysis 2005
	Analyst, Rate Design 2004
	Senior Analyst, DSM Planning and Evaluation 2002
	Senior Economic Analyst, Economic & Financial Studies 1998
	Margaret Chase Smith Center for Public Policy
	Research Assistant 1995
Education:	Master of Arts in Economics University of Maine, 1995
	Bachelor of Arts in Economics University of Maine, 1993
Appearances:	(ONTARIO ENERGY BOARD)

EB-2017-0102	EB-2017-0086
EB-2016-0215	EB-2015-0114
EB-2015-0122	EB-2014-0276
EB-2012-0459	EB-2011-0354
EB-2011-0277	EB-2010-0146
EB-2009-0172	EB-2008-0219
EB-2008-0106	

(RÉGIE DE L'ÉNERGIE)

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

CURRICULUM VITAE OF
HILARY THOMPSON

Experience: Enbridge Gas Distribution Inc.

Director, Asset Management
2016

Manager, Distribution Planning
2014

Manager, Regulatory Projects
2012

Manager, Technical Services
2011

Field Manager, Measurement & Regulation
2011

Senior Engineering Project Leader, Measurement & Regulation
2010

Senior Engineering Project Leader, Special Projects
2008

Engineering Project Leader, Special Projects
2007

Engineering Project Leader, Engineering Standards & Technical Services
2006

Education: University of Toronto – Faculty of Law
Global Professional Master of Laws

Queen's University – Faculty of Applied Science
Bachelor of Science, Chemical Engineering

Memberships: Professional Engineers Ontario (P.Eng. Licence Holder)

Appearances: (Ontario Energy Board)

EB-2017-0306/EB-2017-0307
EB-2017-0102
EB-2015-0049

CURRICULUM VITAE OF
JOHN TIDEMAN

Experience: Enbridge Gas Distribution Inc.

Manager, Residential DSM Programs
2016

Sr. Manager, Organisational Change Management
2014

Sr. Manager Sales and Marketing, Demand Side Management
2011

Manager, Business Development
2006

Direct Energy

Business Development Manager
2003

Total

Sales Manager
1995

Accounting Trainee, Financial Reporting
1984

Education: Kingston University Business School – MBA
Feb 2000

Durham College – Marketing
1998

Appearances: (Ontario Energy Board)

None

CURRICULUM VITAE OF
RAKESH TORUL

Experience: Enbridge Gas Distribution Inc.

Regulatory Applications Specialist II, Regulatory Policy and Strategy
2018

Specialist, Regulatory Accounting
2013

Senior Financial Analyst, Financial Planning and Analysis
2010

Business Support Analyst, Customer Care Financial Administration
2008

AIG Canada

Corporate Accountant
2007

CIBC Mellon

Specialist, Client Advisor Services
2005

Education: Chartered Professional Accountant, Certified Management Accountant
Chartered Professional Accountant of Ontario, 2014
The Society of Management Accountant of Ontario, 2009

Membership: Chartered Professional Accountant of Ontario

Appearances: (Ontario Energy Board)

None

CURRICULUM VITAE OF
CHRISTOPHER G. TUCKWELL

Experience: Union Gas Limited and Enbridge Gas Distribution

Director of Accounting
2018

Union Gas Limited

Controller
2017

Enterprise Manager, Accounts Payable
2016

Manager, Audit Services
2014

Manager S&T Revenue and Gas Accounting
2010

Assistant Controller
2008

Manager, Financial Reporting
2004

Team Lead, Financial Reporting
2002

London Life Insurance Company

Assistant Audit Manager
2001

PricewaterhouseCoopers

Manager
1998

KPMG

Senior Accountant
1995

Education:	Chartered Accountant 1998
	Bachelor of Commerce University of Windsor, 1995
	Bachelor of Arts Wilfrid Laurier University, 1992
Memberships:	Institute of Chartered Accountants of Ontario
	Canadian Institute of Chartered Accountants
Appearances:	(Ontario Energy Board)
	EB-2017-0306/EB-2017-0307 EB-2011-0210 EB-2009-0422 EB-2009-0101

CURRICULUM VITAE OF
LARRY WIGELIUS

Experience:	Enbridge Gas Distribution Inc.
	Lead GL & Consolidation 2014
	Finance Renewal Project 2012
	Supervisor Financial Reporting 2005
	Financial Analyst 2000
Education:	CPA CGA, 2002
	Honours Bachelor of Commerce, Laurentian University, 1986
Memberships:	CPA Ontario
Appearances:	(Ontario Energy Board)
	None

CURRICULUM VITAE OF
FION ZHAO

Experience:	Enbridge Gas Distribution Inc.
	Team Lead, Business Performance May 2018
	Financial Advisor, Business Performance June 2012
	Union Gas
	Senior Performance Measurement Specialist, Business Performance 2007
	Senior Audit Consultant, Internal Audit 2004
	Product & Services Costing Analyst, Regulatory 2001
Education:	Master of Business Administration (MBA) – Wilfrid Laurier University 2001
	Civil Engineering – TongJi University 1993
Memberships:	CPA Ontario CMA Ontario
Appearances:	(Ontario Energy Board)
	None

2017 EARNINGS SHARING AMOUNT AND DETERMINATION PROCESS

1. The 2017 Earnings Sharing amount included within Enbridge Gas Distribution Inc.'s (Enbridge, or the Company) Fiscal 2017 year-end audited statements was $23.7 million, which was slightly higher than the amount being requested for approval and clearance within this application of $23.55 million. In order to meet year end timing obligations, estimates for elements impacting the accrual are sometimes required in lieu of complete or detailed analyses along with the rounding of various actual amounts into millions of dollars for regulatory presentation. Following the year end close process, however, completion of analyses are performed for elements where estimates were used along with rounding finalizations, in order to ensure the earnings sharing amount is accurate. If required and appropriate, an adjustment is made to the earnings sharing results, which ultimately is reflected in following year financial statements. In certain other instances, new information becomes available which requires the earnings sharing amount to be recalculated.

2. The process followed is the same as that which was followed for earnings sharing amounts calculated for 2014 through 2016, and during the 2008 through 2012 incentive regulation term. For 2017, the year-end earnings sharing provision reflected in the financial statements were based on a calculation utilizing an 11+1 forecast. Subsequent to year end, all elements of the earnings sharing calculation (i.e., utility rate base, income, capital structure, etc.) were updated to reflect full year actual results, which caused a $0.3 million decrease in the gross sufficiency to be shared with rate payers, and a corresponding $0.15 million decrease to the earnings sharing amount.

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

4. The earnings sharing amount was determined in accordance with the following prescribed methodology as identified within the EB-2012-0459 Board Decision, dated July 17, 2014, at pages 13 through 15, and within the pre-filed evidence at Exhibit A2, Tab 7, Schedule 1;

   - if in any calendar year during the customized incentive regulation term, Enbridge's actual utility ROE, calculated on a weather normalized basis, is more than the allowed ROE included in that year's rates (updated annually by the application of the Board's ROE Formula), then the resultant amount shall be shared equally (i.e., 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, and amounts related to Open Bill program incentives.

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

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

Part A)

8. The level of utility income, $423.8 million (Line 17) divided by the level of utility rate base, $6,465.2 million (Line 22) generates a utility return on rate base of 6.555% (Line 23).

9. When compared to the Company's required rate of return of 6.019% (Line 24), as determined within the capital structure required in support of the determined rate base amount, there is a resulting sufficiency of 0.536% (Line 25) on total rate base.

10. As shown in Lines 26 through 28, the sufficiency of 0.536% multiplied by the rate base of $6,465.2 million, produces a net over earnings or sufficiency of $34.65 million which from a pre-tax perspective, ($34.65 million divided by the reciprocal, 73.5%, of the corporate tax rate which is 26.5%) shows a $47.14 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 $424.8 million (Line 31) of utility income before income tax, less utility taxes of $1.0 million (Line 36), produces the $423.8 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) $423.8 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 $239.0 million, shown at Line 37.

15. The $239.0 million, divided by the deemed common equity level of $2,327.5 million (Line 38, calculated as 36% of the $6,465.2 million rate base) produces a return on equity of 10.269% (Line 40). When comparing the 10.269% achieved return on equity to the threshold ROE percentage of 8.78% (Line 39), which is the Board approved formula return on equity for 2017, there is a sufficiency in ROE of 1.489% (Line 41).

16. The 1.489% multiplied by the common equity level of $2,327.5 million (Line 38) produces a net over earnings or sufficiency of $34.64 million which from a pre-tax perspective ($34.64 million divided by the reciprocal, 73.5%, of the corporate tax rate), shows a $47.13 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 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 and 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, 2017

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Normalized ($millions) & (%'s)
1.	Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency		
2.	Gas Sales	(Ex.B,T5,S2,P1,Col.1,line 1)	2,503.4
3.	Transportation Revenue	(Ex.B,T5,S2,P1,Col.1,line 2)	308.2
4.	Transmission, Compr. and Storage Revenue	(Ex.B,T5,S2,P1,Col.1,line 3)	19.0
5.	Less Cost of Gas	(Ex.B,T5,S2,P1,Col.1,line 8)	1,668.0
6.	Gas Distribution Margin		1,162.6
7.	Other Revenue	(Ex.B,T5,S2,P1,Col.1,line 4)	42.1
8.	Other Income	(Ex.B,T5,S2,P1,Col.1,line 6)	0.3
9.	Total - Other Revenue & Income		42.4
10.	Operations & Maintenance (incl. CC/CIS rate smoothing adj.)	(Ex.B,T5,S2,P1,Col.1,line 9)	431.5
11.	Depreciation & amortization	(Ex.B,T5,S2,P1,Col.1,line 10)	301.3
12.	Fixed financing costs	(Ex.B,T5,S2,P1,Col.1,line 11)	2.8
13.	Municipal & capital taxes	(Ex.B,T5,S2,P1,Col.1,line 12)	44.6
14.	Total O&M, Depr., & other		780.2
15.	Utility Income before Income Tax	(line 5 + line 9 - line 14)	424.8
16.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	1.0
17.	Utility Income		423.8
18.	Gross plant	(Ex.B,T2,S1,P1,Col.1,line 1)	9,228.8
19.	Accumulated depreciation	(Ex.B,T2,S1,P1,Col.1,line 2)	(3,126.5)
20.	Net plant		6,102.3
21.	Working capital	(Ex.B,T2,S1,P1,Col.1,line 11)	362.9
22.	Utility Rate Base		6,465.2
23.	Indicated Return on Rate Base %	(line 17 / line 22)	6.555%
24.	Less: Required Rate of Return %	(Ex.B,T5,S1,P1,Col.4,line 6)	6.019%
25.	(Deficiency) / Sufficiency %		0.536%
26.	Net Earnings (Deficiency) / Sufficiency	(line 25 x line 22)	34.65
27.	Provision for Income Taxes		12.49
28.	Gross Earnings (Deficiency) / Sufficiency	(line 26 divide by 73.5%)	47.14
29.	50% Earnings sharing to ratepayers	(line 28 x 50%)	23.57
30.	Part B) Return on Equity & Revenue (Deficiency) / Sufficiency		
31.	Utility Income before Income Tax	(Ex.B,T5,S2,P1,Col.1,line 16)	424.8
32.	Less: Long Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 1)	178.7
33.	Less: Short Term Debt Costs	(Ex.B,T5,S1,P1,Col.5,line 2)	3.8
34.	Less: Cost of Preferred Capital	(Ex.B,T5,S1,P1,Col.5,line 4)	2.3
35.	Net Income before Income Taxes		240.0
36.	Less: Income Taxes	(Ex.B,T5,S2,P1,Col.1,line 17)	1.0
37.	Net Income Applicable to Common Equity	(line 35 - line 36)	239.0
38.	Common Equity	(Ex.B,T5,S1,P1,Col.1,line 5)	2,327.5
39.	Approved ROE %		8.780%
40.	Achieved Rate of Return on Equity %	(line 37 divide by line 38)	10.269%
41.	Resulting (Deficiency) / Sufficiency in Return on Equity %		1.489%
42.	Net Earnings (Deficiency) / Sufficiency	(line 38 x line 41)	34.64
43.	Provision for Income Taxes		12.48
44.	Gross Earnings (Deficiency) / Sufficiency	(line 42 divide by 73.5%)	47.13
45.	50% Earnings sharing to ratepayers	(line 44 x 50%)	23.56

ENBRIDGE GAS DISTRIBUTION
CONTRIBUTORS TO UTILITY EARNINGS
AND EARNINGS SHARING AMOUNTS (INCLUDING CUSTOMER CARE & CIS)
2017 ACTUAL

Line No.		Col. 1 2017 Actual Normalized $Millions	Col. 2 2017 Board Approved $Millions	Col. 3 Over/ (Under) Earnings Impact $Millions	Col. 4 Attached Pages Refer.
1.	Sales revenue	2,503.4	2,451.5		
2.	Transportation revenue	308.2	288.3		
3.	Transmission, compression & storage (incl. Rate 332)	19.0	19.1		
4.	Gas costs	1,668.0	1,603.1		
5.	Distribution margin	1,162.6	1,155.8	6.8	a)
6.	Other revenue	42.1	42.7	(0.6)	b)
7.	Other income	0.3	0.1	0.2	b)
8.	O&M (incl. CC/CIS rate smoothing adj.)	431.5	462.7	31.2	c)
9.	Depreciation expense	301.3	297.7	(3.6)	d)
10.	Other expense	47.4	49.8	2.4	e)
11.	Income taxes	1.0	14.4	13.4	f)
12.	Utility Income	423.8	374.0	49.8	
13.	LTD & STD costs	182.5	181.4	(1.1)	g)
14.	Preference share costs	2.3	2.2	(0.1)	
15.	Return on Equity @ 9.19% in 2016 Board Approved	204.3	190.4	(13.9)	
16.	Net Earnings Over / (Under) (aft. prov for taxes)	34.7	-	34.7	
17.	Provision for taxes on Earnings Over / (Under)	12.4	-	12.4	
18.	Gross Earnings Over / (Under)	47.1	-	47.1	
19.	EGD Equity Level @ 36% (B-5-1, Col.1. line 5)	2,327.5			
20.	EGD normalized Earnings (Line12 - line 13 - line 14)	239.0			
21.	EGD normalized Return on Equity	10.27%			

2017 EARNINGS SHARING AMOUNT AND CONTRIBUTORS

The following are explanations of the Utility Normalized Earnings results as compared to the 2017 Board approved amounts. The reference letters are in relation to those identified on page 1 of this Schedule.

a) The distribution margin increase of $6.8 million was driven primarily due to a higher than forecast overall average number of customer unlocks, attributable to higher than forecast customer additions, higher than forecast gas in storage carrying charges reflected in rates, as a result of higher than forecast PGVA reference prices approved through the 2017 Quarterly Rate Adjustment Mechanism (QRAM) proceedings, and lower fuel costs required to manage storage operations and the transmission of volumes on Union’s system. Higher margin resulted in a positive earnings impact.

b) The net decrease in other revenue and other income of $0.4 million resulted in a negative earnings impact. Details of other revenue and other income are presented in Exhibit B, Tab 3, Schedule 5.

c) Utility O&M was $31.2 million lower than the 2017 Board approved level which resulted in a positive earnings impact. Explanations of the major changes between actual and Board approved O&M are presented in Exhibit B, Tab 4, Schedule 2.

d) The increase in depreciation expense of $3.6 million was predominantly due to the cumulative impact of capital variances (level and mix of capital spending and level of retirements) from prior years (2012 – 2016) which were not reflected in the 2017 depreciable balances approved by the Ontario Energy Board for rate setting as part of the customized incentive rate proceeding. The increase in depreciation resulted in a negative earnings impact.

e) The decrease in other expenses of $2.4 million was due to lower municipal taxes of $3.3 million, partially offset by higher fixed financing charges of $0.9 million. The favourable municipal tax variance was attributable to lower than forecast municipal tax rate increases. The unfavourable variance in fixed financing charges was attributable to the unforecast increase in the Company’s credit facility which occurred in 2014. The net decrease resulted in a positive earnings impact.

f) The decrease in income taxes of $13.4 million was primarily attributable to higher than forecast actual 2017 tax deductible amounts, predominantly due to higher CCA and cost of retirements. The decrease resulted in a positive earnings impact.

g) The interest cost of utility long and short term debt increased by $1.1 million primarily as a result of a higher outstanding principal balance required to fund the higher than forecast actual rate base value. The impact of the higher principal balance was largely offset by a lower weighted average cost of debt rate, which was attributable to the change in the component percentages of long (decrease) and short term (increase) debt. The lower long term debt component percentage, was partially attributable to the lower than forecast average of monthly average long-term debt balance outstanding that resulted from issuing $300 million later in the year, November 2017 as compared to August 2017, than forecast. The net increase has a negative earnings impact.

RECONCILIATION OF AUDITED ENBRIDGE GAS DISTRIBUTION INC
CONSOLIDATED INCOME TO UTILITY INCOME
2017 ACTUAL

Line no.		Col. 1 Audited Consolidated Income ($millions)	Col. 2 Utility Income ($millions)	Col. 3 Difference ($millions)	Col. 4 Reference
1.	Gas commodity and distribution revenue	2,759.7	2,503.4	(256.3)	a)
2.	Transportation of gas for customers	417.8	308.2	(109.6)	b)
3.	Other revenue and income	178.1	61.4	(116.7)	c)
4.		3,355.6	2,873.0	(482.6)	
	Expenses				
5.	Gas commodity and distribution costs	2,031.8	1,668.0	(363.8)	d)
6.	Operation and maintenance	520.2	431.5	(88.7)	e)
7.	Earnings sharing	23.9	-	(23.9)	f)
8.	Depreciation	330.0	301.3	(28.7)	g)
9.	Municipal and other taxes	-	44.6	44.6	h)
10.		2,905.9	2,445.4	(460.5)	
11.	Income before undernoted items	449.7	427.6	(22.1)	
12.	Interest and financing expenses	(214.2)	(2.8)	211.4	i)
13.	Income before income taxes	235.5	424.8	189.3	
14.	Income taxes	14.0	(1.0)	(15.0)	j)
15.	Net Income	249.5	423.8	174.3	

RECONCILIATION OF 2017
AUDITED ENBRIDGE GAS DISTRIBUTION INC CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
a)	2,759.7	**Consolidated gas commodity and distribution revenue**
	(36.4)	Amounts related to St. Lawrence Gas
	37.6	Normalization adjustment
	(5.7)	Elimination of US GAAP adjustment for deferral clearance recognition
	(255.4)	Removal of Cap and Trade revenues
	3.5	Gazifere T-service regrouped to gas commodity and distribution revenue
	0.1	Rounding
	2,503.4	**Utility gas commodity and distribution revenue**
b)	417.8	**Consolidated transportation of gas for customers**
	(13.1)	Amounts related to St. Lawrence Gas
	4.9	Normalization adjustment
	(97.9)	Removal of Cap and Trade revenues
	(3.5)	Gazifere T-service regrouped to gas commodity and distribution revenue
	308.2	**Utility transportation of gas for customers**
c)	178.1	**Consolidated other revenue and income**
	(29.4)	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
	0.2	Foreign exchange gain and other misc. expenses regrouped to O&M
	4.8	Allowable interest during construction regrouped to revenues from interest and financing expenses
	1.3	Interest on deferral accounts regrouped to revenues from interest and financing expenses
	(1.1)	ABC administration and bad debt costs regrouped against program revenues from O&M
	(13.0)	Open Bill expenses regrouped against program revenues from O&M
	(1.1)	Elimination of transactional services revenue above base amount included in rates
	(1.1)	To adjust OBA costs to reflect the EB-2013-0099 approved unit costs for determining net revenues
	(1.7)	Elimination of Open Bill revenues to reflect the shareholder incentive
	(0.9)	Elimination of 3rd party asset use revenue considered non-utility
	(1.2)	Elimination of net ABC revenue considered non-utility
	(1.7)	Elimination of interest income from investments not included in rate base
	(4.8)	Elimination of allowable interest during construction
	(1.3)	Elimination of interest on deferral accounts
	(2.9)	Elimination of shareholder incentive income associated with the DSMIDA
	(0.1)	Rounding
	61.4	**Utility other revenue and income**

RECONCILIATION OF 2017
AUDITED ENBRIDGE GAS DISTRIBUTION INC CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
d)	2,031.8	**Consolidated gas commodity and distribution costs**
	(40.7)	Elimination of amounts related to St. Lawrence Gas, unregulated storage
	27.2	Normalization adjustment
	3.0	Elimination of US GAAP adjustment for deferral clearance recognition
	(353.3)	Removal of Cap and Trade costs
	1,668.0	**Utility gas commodity and distribution costs**
e)	520.2	**Consolidated operation and maintenance**
	(47.9)	Municipal and other taxes included within O&M costs in the corp. financial statements
	(16.1)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(13.0)	Open Bill expenses regrouped against program revenues
	(1.1)	ABC administration and bad debt costs regrouped against program revenues and eliminated
	0.2	Foreign exchange gain and other misc. expenses regrouped from Other income
	0.6	Interest on security deposits added to utility O&M
	(0.8)	Elimination of donations
	(0.7)	Elimination of non-utility costs of supporting the ABC program
	0.7	Elimination of electric CDM net revenues in O&M
	(0.2)	Elimination of EGD/Union Amalgamation transaction costs
	(8.7)	Elimination of US GAAP adjustment for deferral clearance recognition
	(1.6)	Elimination of Corporate Cost Allocations above RCAM amount
	(0.1)	Rounding
	431.5	**Utility operation and maintenance**
f)	23.9	**Consolidated earnings sharing**
	(23.9)	Elimination of earnings sharing amount within year end financials from utility income calculation
	-	**Utility earnings sharing**
g)	330.0	**Consolidated depreciation**
	(5.4)	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
	301.3	**Utility depreciation**

RECONCILIATION OF 2017
AUDITED ENBRIDGE GAS DISTRIBUTION INC CONSOLIDATED INCOME TO UTILITY INCOME

Ref.s	Amount ($million)	Reclassification and elimination of revenue / expense items
h)	-	**Consolidated municipal and other taxes**
	47.9	Municipal and other taxes included within O&M costs in the corp. financial statements
	(3.1)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	(0.2)	Elimination of municipal taxes related to shared assets
	44.6	**Utility municipal and other taxes**
i)	214.2	**Consolidated interest and financing expenses**
	(3.7)	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
	4.8	Allowable interest during construction regrouped to revenues and eliminated
	1.3	Interest on deferral accounts regrouped to revenues and eliminated
	(187.0)	Elimination of interest expense and the amortization of debt issue and discount costs which are determined through the regulated capital structure
	2.8	**Utility interest and financing expenses**
j)	(14.0)	**Consolidated income taxes**
	(2.3)	Amounts related to St. Lawrence Gas, unregulated storage, oil and gas
	16.3	Elimination of corporate income taxes
	1.0	Addition of income taxes calculated on a utility "stand-alone" basis
	1.0	**Utility income taxes**

UTILITY RATE BASE (INCLUDING CUSTOMER CARE & CIS)
COMPARISON OF 2017 ACTUAL TO 2017 BOARD APPROVED

Line No.		Col. 1 2017 Actual	Col. 2 EB-2016-0215 2017 Board Approved	Col. 3 Variance
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	9,228.8	8,913.7	315.1
2.	Accumulated depreciation	(3,126.5)	(3,217.8)	91.3
3.	Net property, plant, and equipment	6,102.3	5,695.9	406.4
	Allowance for Working Capital			
4.	Accounts receivable rebillable projects	1.4	1.4	-
5.	Materials and supplies	36.2	34.6	1.6
6.	Mortgages receivable	-	-	-
7.	Customer security deposits	(47.2)	(64.6)	17.4
8.	Prepaid expenses	1.4	1.0	0.4
9.	Gas in storage	372.0	356.6	15.4
10.	Working cash allowance	(0.9)	(0.8)	(0.1)
11.	Total Working Capital	362.9	328.2	34.7
12.	Utility Rate Base	6,465.2	6,024.1	441.1

UTILITY PROPERTY, PLANT, AND EQUIPMENT (EXCLUDING CIS & CUSTOMER CARE)
SUMMARY STATEMENT - AVERAGE OF MONTHLY AVERAGES
2017 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	410.7	(136.6)	274.1
2.	Distribution plant	8,264.5	(2,655.5)	5,609.0
3.	General plant	563.8	(335.9)	227.9
4.	Other plant	-	-	-
5.	Total plant in service	9,239.0	(3,128.0)	6,111.0
6.	Plant held for future use	1.7	(1.3)	0.4
7.	Sub- total	9,240.7	(3,129.3)	6,111.4
8.	Affiliate Shared Assets Value	(11.9)	2.8	(9.1)
9.	Total property, plant, and equipment	9,228.8	(3,126.5)	6,102.3

UTILITY GROSS UNDERGROUND STORAGE PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustments (Note 1)	Col. 6 Utility Balance Dec.2017	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)	46.0	-	-	46.0	(1.0)	45.0	45.0
3.	Structures and improvements (452.00)	29.5	1.9	(0.5)	30.9	(0.1)	30.9	30.0
4.	Wells (453.00)	53.1	0.3	(0.4)	52.9	-	52.9	53.2
5.	Well equipment (454.00)	11.1	0.0	(0.1)	10.9	-	10.9	11.1
6.	Field Lines (455.00)	93.6	6.3	(0.3)	99.7	-	99.7	97.6
7.	Compressor equipment (456.00)	124.0	5.1	-	129.1	(0.5)	128.7	125.1
8.	Measuring and regulating equipment (457.00)	11.2	-	(0.0)	11.2	-	11.2	11.2
9.	Base pressure gas (458.00)	33.4	-	-	33.4	-	33.4	33.4
10.	Total	406.0	13.6	(1.3)	418.3	(1.5)	416.8	410.7

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

UTILITY UNDERGROUND STORAGE PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2017	Col. 7 Regulatory Adjustments (Note 1)	Col. 8 Utility Balance Dec.2017	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Crowland storage (450/459)	(2.5)	(0.1)	-	-	-	(2.6)	-	(2.6)	(2.6)
2.	Land and gas storage rights (451.00)	(23.8)	(0.5)	-	-	-	(24.3)	-	(24.3)	(24.0)
3.	Structures and improvements (452.00)	(3.2)	(0.6)	-	0.5	-	(3.3)	0.1	(3.3)	(3.4)
4.	Wells (453.00)	(19.9)	(0.8)	(0.0)	0.4	-	(20.3)	-	(20.3)	(20.3)
5.	Well equipment (454.00)	(6.3)	(0.6)	-	0.1	-	(6.8)	-	(6.8)	(6.6)
6.	Field Lines (455.00)	(27.5)	(1.5)	(0.0)	0.3	-	(28.7)	-	(28.7)	(28.2)
7.	Compressor equipment (456.00)	(43.1)	(3.3)	(0.1)	-	-	(46.4)	0.2	(46.2)	(44.5)
8.	Measuring and regulating equipment (457.00)	(6.8)	(0.3)	(0.0)	0.0	-	(7.1)	-	(7.1)	(7.0)
9.	Total	(133.1)	(7.7)	(0.1)	1.3	-	(139.5)	0.3	(139.2)	(136.6)

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

UTILITY GROSS DISTRIBUTION PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment (Note 1)	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land (470.00)	23.2	0.0	(0.0)	23.2	-	23.2	23.2
2.	Offers to purchase (470.01)	-	-	-	-	-	-	-
3.	Land rights intangibles (471.00)	63.9	(0.2)	-	63.7	-	63.7	63.7
4.	Structures and improvements (472.00)	123.8	19.4	(1.2)	142.0	(0.3)	141.7	136.0
5.	Services, house reg & meter install. (473/474)	2,739.3	116.9	(7.6)	2,848.6	-	2,848.6	2,772.8
6.	NGV station compressors (476)	3.6	0.1	-	3.6	-	3.6	3.6
7.	Meters (478)	426.4	21.7	(27.0)	421.1	-	421.1	433.6
8.	Sub-total	3,380.2	157.8	(35.8)	3,502.2	(0.3)	3,501.9	3,432.9
9.	Mains (475)	4,197.7	167.3	(2.9)	4,362.1	(2.2)	4,359.9	4,275.0
10.	Measuring and regulating equip. (477)	523.0	70.3	(2.3)	591.1	(0.5)	590.6	556.6
11.	Sub-total	4,720.8	237.6	(5.2)	4,953.1	(2.7)	4,950.4	4,831.7
12.	Total	8,100.9	395.4	(41.0)	8,455.3	(3.1)	8,452.3	8,264.5

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
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Net Salvage Adjustment	Col. 4 Retirements	Col. 5 Costs Net of Proceeds	Col. 6 Closing Balance Dec.2017	Col. 7 Regulatory Adjustment (Note 1)	Col. 8 Utility Balance Dec.2017	Col. 9 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Land rights intangibles (471.00)	(2.7)	(0.8)	-	-	-	(3.5)	-	(3.5)	(3.1)
2.	Structures and improvements (472.00)	(11.8)	(8.7)	-	1.2	0.5	(18.8)	0.2	(18.6)	(15.0)
3.	Services, house reg & meter install. (473/474)	(1,034.2)	(62.9)	26.2	7.6	18.2	(1,045.1)	-	(1,045.1)	(1,037.9)
4.	NGV station compressors (476)	(2.3)	(0.2)	-	-	-	(2.6)	-	(2.6)	(2.5)
5.	Meters (478)	(191.1)	(31.3)	-	27.0	(0.7)	(196.0)	-	(196.0)	(206.6)
6.	Mains (475)	(1,167.8)	(95.6)	51.0	2.9	27.4	(1,182.1)	1.8	(1,180.3)	(1,169.6)
7.	Measuring and regulating equip. (477)	(216.9)	(12.2)	0.3	2.3	-	(226.4)	0.5	(225.9)	(220.8)
8.	Total	(2,626.7)	(211.7)	77.6	41.0	45.5	(2,674.4)	2.5	(2,671.9)	(2,655.5)

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

UTILITY GROSS GENERAL PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	1.3	0.0	(1.2)	0.1	(0.2) [1]	(0.1)	0.4
2.	Office furniture and equipment (483.00)	20.0	1.1	(1.2)	20.0	-	20.0	20.2
3.	Transportation equipment (484.00)	49.6	5.4	(3.3)	51.7	(0.1) [1]	51.6	48.6
4.	NGV conversion kits (484.01)	2.1	0.4	(0.2)	2.3	-	2.3	2.1
5.	Heavy work equipment (485.00)	15.9	0.3	(0.6)	15.6	-	15.6	15.8
6.	Tools and work equipment (486.00)	48.1	2.6	(1.2)	49.5	-	49.5	48.7
7.	Rental equipment (487.70)	1.6	-	-	1.6	-	1.6	1.6
8.	NGV rental compressors (487.80)	6.9	1.7	(0.6)	8.0	-	8.0	6.9
9.	NGV cylinders (484.02 and 487.90)	0.6	-	-	0.6	-	0.6	0.6
10.	Communication structures & equip. (488)	2.9	1.0	-	3.9	-	3.9	3.4
11.	Computer equipment (490.00)	28.1	4.9	(8.2)	24.8	-	24.8	24.4
12.	Software Aquired/Developed (491.00)	178.5	27.2	(15.0)	190.7	-	190.7	172.2
13.	CIS (491.00)	127.1	-	-	127.1	-	127.1	127.1
14.	WAMS (489.00)	90.1	2.0	-	92.0	-	92.0	91.8
15.	Total	572.8	46.6	(31.4)	588.0	(0.3)	587.8	563.8

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
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2017	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2017	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Lease improvements (482.50)	(1.2)	(0.0)	1.2	-	(0.0)	0.2 [1]	0.2	(0.4)
2.	Office furniture and equipment (483.00)	(5.0)	(2.2)	1.2	-	(6.0)	-	(6.0)	(5.7)
3.	Transportation equipment (484.00)	(17.4)	(5.2)	3.3	(0.4)	(19.6)	0.1 [1]	(19.6)	(18.3)
4.	NGV conversion kits (484.01)	1.0	(0.2)	0.2	-	1.0	-	1.0	1.0
5.	Heavy work equipment (485.00)	(4.4)	(0.6)	0.6	(0.2)	(4.6)	-	(4.6)	(4.7)
6.	Tools and work equipment (486.00)	(15.1)	(2.0)	1.2	-	(15.9)	-	(15.9)	(16.0)
7.	Rental equipment (487.70)	(1.1)	(0.0)	-	-	(1.1)	-	(1.1)	(1.1)
8.	NGV rental compressors (487.80)	(0.8)	(0.6)	0.6	-	(0.8)	-	(0.8)	(0.9)
9.	NGV cylinders (484.02 and 487.90)	(0.4)	(0.0)	-	-	(0.5)	-	(0.5)	(0.5)
10.	Communication structures & equip. (488)	(0.5)	(0.4)	-	-	(0.9)	-	(0.9)	(0.7)
11.	Computer equipment (490.00)	(23.9)	(9.3)	8.2	-	(24.9)	-	(24.9)	(22.8)
12.	Software Aquired/Developed (491.00)	(152.5)	(40.4)	15.0	-	(177.9)	-	(177.9)	(161.3)
13.	CIS (491.00)	(92.2)	(12.7)	-	-	(104.9)	-	(104.9)	(98.5)
14.	WAMS (489.00)	(1.6)	(9.2)	-	-	(10.7)	-	(10.7)	(6.2)
15.	Total	(314.8)	(82.7)	31.4	(0.6)	(366.6)	0.2	(366.4)	(335.9)

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

UTILITY GROSS OTHER PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	-	-	-	-	-	-	-
2.	Total	-	-	-	-	-	-	-

UTILITY OTHER PLANT
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2017	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2017	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Intangible plant (Peterborough 402.50)	-	-	-	-	-	-	-	-
2.	Total	-	-	-	-	-	-	-	-

UTILITY GROSS PLANT HELD FOR FUTURE USE
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Closing Balance Dec.2017	Col. 5 Regulatory Adjustment	Col. 6 Utility Balance Dec.2017	Col. 7 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (102.00)	1.7	-	-	1.7	-	1.7	1.7
2.	Total	1.7	-	-	1.7	-	1.7	1.7

UTILITY PLANT HELD FOR FUTURE USE
CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 ACTUAL

Line No.		Col. 1 Opening Balance Dec.2016	Col. 2 Additions	Col. 3 Retirements	Col. 4 Costs Net of Proceeds	Col. 5 Closing Balance Dec.2017	Col. 6 Regulatory Adjustment	Col. 7 Utility Balance Dec.2017	Col. 8 Average of Monthly Averages
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Inactive services (105.02)	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)
2.	Total	(1.3)	(0.0)	-	-	(1.3)	-	(1.3)	(1.3)

WORKING CAPITAL COMPONENTS
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2017 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	1.4	35.2	-	(50.0)	1.3	472.8	(0.9)	459.8
2.	January 31	1.4	35.1	-	(49.5)	1.8	405.4	(0.9)	393.3
3.	February	1.4	34.0	-	(48.6)	1.5	293.3	(0.9)	280.7
4.	March	1.4	34.1	-	(48.0)	1.1	146.8	(0.9)	134.5
5.	April	1.4	34.3	-	(47.5)	0.8	149.0	(0.9)	137.1
6.	May	1.4	34.9	-	(46.7)	0.8	198.7	(0.9)	188.2
7.	June	1.4	34.1	-	(46.1)	0.7	280.1	(0.9)	269.3
8.	July	1.3	35.7	-	(46.3)	2.1	386.8	(0.9)	378.7
9.	August	1.3	37.0	-	(46.3)	2.1	482.8	(0.9)	476.0
10.	September	1.3	39.9	-	(46.1)	1.5	564.7	(0.9)	560.4
11.	October	1.3	42.0	-	(46.4)	1.8	559.7	(0.9)	557.5
12.	November	1.3	37.3	-	(46.8)	1.5	522.4	(0.9)	514.8
13.	December	1.3	37.4	-	(46.7)	1.8	475.9	(0.9)	468.8
14.	Avg. of monthly avgs.	1.4	36.2	-	(47.2)	1.4	372.0	(0.9)	362.9

WORKING CAPITAL COMPONENTS - WORKING CASH ALLOWANCE
2017 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	1,667.0	2.2	10.0
2.	Items not subject to working cash allowance (Note 1)	1.0		
3.	Gas costs charged to operations	1,668.0		
4.	Operation and Maintenance	431.5		
5.	Less: Storage costs	(8.4)		
6.	Operation and maintenance costs subject to working cash	423.1		
7.	Ancillary customer services	-		
8.		423.1	(10.9)	(12.6)
9.	Sub-total			(2.6)
10.	Storage costs	8.4	58.4	1.3
11.	Storage municipal and capital taxes	1.4	22.9	0.1
12.	Sub-total			1.4
13.	Harmonized Sales Tax			0.3
14.	Total working cash allowance			(0.9)

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

COMPARISON OF UTILITY CAPITAL EXPENDITURES
2017 ACTUALS VS. 2017 BOARD APPROVED BUDGET

Table 1
Summary of Capital Expenditures 2017 Actual and 2017 Board Approved Budget
($millions)

	Col 1	Col 2	Col 3
	Actual	Board Approved Budget	Actual Over/(Under)
	2017	2017	2017
Customer Related Distribution Plant	141.3	140.8	0.5
System Improvements and Upgrades	214.1	242.2	(28.1)
General and Other Plant	49.4	48.4	1.0
Underground Storage Plant	19.8	10.5	9.3
Sub total Core Capital Expenditures	**424.5**	**441.9**	**(17.4)**
Work and Asset Management Solution (WAMS)	2.0	-	2.0
GTA Reinforcement	4.8	-	4.8
Sub total Core Special Initiatives	**6.8**	**-**	**6.8**
Total Capital Expenditures	**431.3**	**441.9**	**(10.6)**

1. The 2017 Actual expenditures for Work and Asset Management (“WAMS”) and GTA projects totaled $6.8 million versus a zero Budget in 2017. The variance resulted from carryover costs from 2016 due to delays experienced with these multi-year initiatives. Both projects were budgeted to be in-service by the end of 2015.

2. The 2017 Actual core capital expenditures were $424.5 million, which was $17.4 million less than the 2017 Budget of $441.9 million. Core capital amounts also include overheads (i.e., departmental labour costs, capitalized administrative and general, and interest during construction). Excluding overheads, the 2017 Actual core capital spend was $305.4 million or $16.8 million less than the 2017 Budget of $322.2 million.

3. Table 2 below shows the major drivers of the $10.6 million underspend vs. Board approved budget. Further details are provided below Table 2.

Table 2
Summary of Capital Expenditures 2017 Actual and 2017 Board Approved Budget
($millions)

		Actual Over/(Under)	% Change	Commentary
	Total 2017 Variance	(10.6)	-2%	
A	GTA Reinforcement	4.8	100%	Permit and construction challenges
B	Customer Growth	7.4	7%	Changes in customer and geographic mix
C	Storage	8.1	91%	Remediation of degrading compressor foundations and storage pipeline integrity
D	Facilities and Genl Plant	2.0	12%	Replacement of vehicles/equipment offset by lower spend in building improvements
E	Work and Asset Mgt (WAMS)	2.0	100%	Project warranty and close-out
F	Reinforcements	(4.1)	-46%	Due to project deferrals associated growth
G	Overheads - DLC, A&G and IDC	(0.6)	0%	Lower IDC and A&G spend offset by higher DLC
H	Relocations	(9.1)	-72%	Incremental cost recovery from non-municipal infrastructure parties
I	Information Technology	0.2	1%	IT spend in line with budget
J	Business Development	(1.6)	-42%	Delay in construction of NGV refueling station project
K	System Integrity and Reliability	(19.7)	-14%	Updated project re-prioritization and workforce reductions
		(10.6)	**-2%**	

A. <u>GTA Reinforcement – Overspent by $4.8 Million</u>

4. Construction complexity and project start delays due to permitting pushed overall construction schedule and completion of Ashtonbee station.

B. <u>Customer Growth - Overspent by $7.4 Million</u>

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 $8.1 Million

6. The overage is due to increased spend on remediation of degrading compressor foundations and storage pipeline integrity.

D. Facilities and General Plant – Overspent by $2.0 Million

7. Increased spend of $3.9M of fleet purchases to replace aging vehicles, equipment and tools offset by lower spend in Facilities associated with building improvements and workspace alterations ($1.9M).

E. Work and Asset Management Solution (“WAMS”) – Overspent by $2.0 Million

8. The $2.0M overspend was incurred for the project warranty and close-out.

F. Reinforcements – Underspent by $4.1 Million

9. Reinforcements are primarily driven by customer growth and system reliability considerations to meet the anticipated peak hourly demand. The 2017 spend on reinforcements was lower due to project deferrals associated with growth.

G. Departmental Labour Costs, A&G and IDC – Underspent by $0.6 Million

10. From an overall perspective, these three cost categories were ($0.6M) less than budget. Interest during construction (“IDC”) was lower by ($3.0M) due to lower interest rates and lower Work In Progress (“WIP”) balances from lower capital spend along with lower capitalized administrative and general (“A&G”) of ($0.5M). Partially offset by higher Departmental Labour Costs of $2.9M due to re-allocated labour from direct capital to DLC as WAMS and Asset Management projects were put into service.

H. Relocations - Underspent by $9.1 Million

11. Enbridge is required to relocate its infrastructure to accommodate 3rd party construction. The 2017 variance is primarily due to incremental cost recovery from non-municipal infrastructure parties.

I. Information Technology – Overspent by $0.2 Million

12. IT spend was in line with budget for 2017.

J. Business Development – Underspent by $1.6 Million

13. The variance in the NGV rental program is due to the delay in undertaking construction of an NGV refueling station. The customer's decision to proceed with the station was delayed to 2018.

K. System Integrity and Reliability (SIR) – Underspent by $19.7 Million

14. The SIR portfolio for 2017 was developed using Enbridge Gas Distribution's Asset Management Framework and resulted in portfolio prioritization using risk based assessments. Description of the variances is set out in Exhibit D, Tab 1, Schedule 2.

Witness: S. Riccio

UTILITY OPERATING REVENUE (INCLUDING CUSTOMER CARE & CIS)
2017 ACTUAL

Line No.		Col. 1 Utility Revenue ($Millions)	Col. 2 Normalizing and Other Adjustments ($Millions)	Col. 3 Adjusted Utility Revenue ($Millions)
1.	Gas sales	2,465.8	37.6	2,503.4
2.	Transportation of gas	303.3	4.9	308.2
3.	Transmission, compression & storage	19.0	-	19.0
4.	Other operating revenue	42.1	-	42.1
5.	Interest and property rental	-	-	-
6.	Other income	0.3	-	0.3
7.	Total operating revenue	2,830.5	42.5	2,873.0

EXPLANATION OF ADJUSTMENTS TO UTILITY REVENUE
2017 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease)	Explanation
	($Millions)	
1.	37.6	Gas sales
		Adjustment to gas sales revenue required to reflect normal weather.
2.	4.9	Transportation of gas
		Adjustment to gas sales revenue required to reflect normal weather.

UTILITY REVENUE (INCLUDING CUSTOMER CARE & CIS)
2017 ACTUAL

Line No.		Col. 1 EGDI Ont. Corporate Revenue	Col. 2 Adjustment	Col. 3 Utility Revenue
		($Millions)	($Millions)	($Millions)
1.	Residential	1,920.2	(261.1)	1,659.1
2.	Commercial	699.2	-	699.2
3.	Industrial	77.9	-	77.9
4.	Wholesale	29.6	-	29.6
5.	Gas sales	2,726.9	(261.1)	2,465.8
6.	Transportation of gas	401.2	(97.9)	303.3
7.	Transmission, compression & storage	19.0	-	19.0
8.	Service charges & DPAC	12.8	-	12.8
9.	Rent from NGV rentals	1.3	-	1.3
10.	Late payment penalties	10.3	-	10.3
11.	Transactional services	13.1	(1.1)	12.0
12.	Open bill revenue	8.2	(2.8)	5.4
13.	Dow Moore recovery	0.3	-	0.3
14.	Affiliate asset use revenue	-	-	-
15.	ABC T-service (net)	1.2	(1.2)	-
16.	Other operating revenue	47.2	(5.1)	42.1
17.	Income from investments	1.7	(1.7)	-
18.	Interest during construction	4.8	(4.8)	-
19.	Interest income from affiliates	-	-	-
20.	Interest on (net) deferral accounts	1.3	(1.3)	-
21.	Property/asset use revenue 3rd party	0.9	(0.9)	-
22.	Interest and property rental	8.7	(8.7)	-
23.	Miscellaneous	11.6	(11.3)	0.3
24.	Dividend income	62.7	(62.7)	-
25.	Profit on sale of property	-	-	-
26.	NGV merchandising revenue (net)	-	-	-
27.	Other income	74.3	(74.0)	0.3
28.	Total revenue	3,277.3	(446.8)	2,830.5

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE REVENUE
2017 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1.	(261.1)	Residential gas sales	
		US GAAP adjustment elimination for deferral & variance clearance recognition.	(5.7)
		Removal of Cap and Trade revenues.	(255.4)
			(261.1)
6.	(97.9)	Transportation of Gas	
		Removal of Cap and Trade revenues.	
11.	(1.1)	Transactional services	
		To eliminate transactional services revenues above the base amount to be included in rates. Ratepayer and shareholder amounts above the base will be treated outside of utility results and returns.	
12.	(2.8)	Open bill revenue	
		To adjust OBA costs to reflect the EB-2013-0099 approved unit costs agreed to be used for determining net revenues.	(1.1)
		To eliminate the Open Bill shareholder incentive.	(1.7)
			(2.8)
15.	(1.2)	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
2017 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
17.	(1.7)	Income from investments	
		To eliminate interest income from investments not included in Utility rate base.	
18.	(4.8)	Interest during construction	
		To eliminate interest calculated on funds used for purposes of construction during the year.	
20.	(1.3)	Interest on (net) deferral accounts	
		To eliminate interest income form assets not included in Utility rate base.	
21.	(0.9)	Property/asset use revenue 3rd party	
		To eliminate asset use revenue (RP-2002-0133) and rental revenue from Tecumseh farm properties considered to be non-utility. (EBRO 464 & 365)	
23.	(11.3)	Miscellaneous	
		To eliminate net revenue from the Company's oil & gas and unregulated storage divisions.	(8.4)
		To eliminate the shareholders' incentive income recorded as a result of calculating the 2016 DSMIDA amount.	(2.9)
			(11.3)
24.	(62.7)	Dividend income	
		To eliminate non-utility inter-company dividend income from the financing transaction (EBO 179-16).	

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2017 ACTUAL AND 2017 BOARD APPROVED BUDGET
($10^6 m^3$)

Item No.		Col. 1 2017 Actual		Col. 2 2017 Board Approved Budget		Col. 3 2017 Actual Over (Under) 2017 Budget (1-2)
General Service						
1.1.1	Rate 1 - Sales	4 526.7		4 659.2		(132.5)
1.1.2	Rate 1 - T-Service	212.5		252.3		(39.8)
1.1	Total Rate 1	4 739.2		4 911.5		(172.3)
1.2.1	Rate 6 - Sales	2 758.9		3 104.3		(345.4)
1.2.2	Rate 6 - T-Service	1 941.7		1 757.9		183.8
1.2	Total Rate 6	4 700.6		4 862.2		(161.6)
1.3.1	Rate 9 - Sales	0.0	**	0.3		(0.3)
1.3.2	Rate 9 - T-Service	0.0		0.0		0.0
1.3	Total Rate 9	0.0		0.3		(0.3)
1.	Total General Service Sales & T-Service	9 439.8		9 774.0		(334.2)
Contract Sales						
2.1	Rate 100	0.9		0.0		0.9
2.2	Rate 110	53.8		67.3		(13.5)
2.3	Rate 115	0.1		0.0		0.1
2.4	Rate 135	2.9		1.2		1.7
2.5	Rate 145	6.9		8.3		(1.4)
2.6	Rate 170	32.6		35.7		(3.1)
2.7	Rate 200	173.9		170.8		3.1
2.	Total Contract Sales	271.1		283.3		(12.2)
Contract T-Service						
3.1	Rate 100	0.3		0.0		0.3
3.2	Rate 110	744.4		794.2		(49.8)
3.3	Rate 115	508.5		490.3		18.2
3.4	Rate 125	0.0	*	0.0	*	0.0
3.5	Rate 135	63.1		59.7		3.4
3.6	Rate 145	39.2		55.1		(15.9)
3.7	Rate 170	280.1		260.6		19.5
3.8	Rate 300	0.0		35.0		(35.0)
3.9	Rate 315	0.0		0.0		0.0
3.	Total Contract T-Service	1 635.6		1 694.9		(59.3)
4.	Total Contract Sales & T-Service	1 906.7		1 978.2		(71.5)
5.	Total	11 346.5		11 752.2		(405.7)

* There is no distribution volume for Rate 125 customers.

** Less than 50,000 m^3

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2017 ACTUAL AND 2017 BOARD APPROVED BUDGET
(10^6m^3)

Item No.		Col. 1 2017 Actual		Col. 2 2017 Board Approved Budget	Col. 3 2017 Actual Over (Under) 2017 Budget (1-2)	Col. 4 2017* Adjustments	Col. 5 2017 Actual Over (Under) 2017 Budget with Adjustments (3+4)
General Service							
1.1.1	Rate 1 - Sales	4 526.7		4 659.2	(132.5)	192.5	60.0
1.1.2	Rate 1 - T-Service	212.5		252.3	(39.8)	10.1	(29.7)
1.1	Total Rate 1	4 739.2		4 911.5	(172.3)	202.6	30.3
1.2.1	Rate 6 - Sales	2 758.9		3 104.3	(345.4)	131.0	(214.4)
1.2.2	Rate 6 - T-Service	1 941.7		1 757.9	183.8	79.5	263.3
1.2	Total Rate 6	4 700.6		4 862.2	(161.6)	210.5	48.9
1.3.1	Rate 9 - Sales	0.0	**	0.3	(0.3)	0.0	(0.3)
1.3.2	Rate 9 - T-Service	0.0		0.0	0.0	0.0	0.0
1.3	Total Rate 9	0.0		0.3	(0.3)	0.0	(0.3)
1.	Total General Service Sales & T-Service	9 439.8		9 774.0	(334.2)	413.1	78.9
Contract Sales							
2.1	Rate 100	0.9		0.0	0.9	0.0	0.9
2.2	Rate 110	53.8		67.3	(13.5)	0.1	(13.4)
2.3	Rate 115	0.1		0.0	0.1	0.0	0.1
2.4	Rate 135	2.9		1.2	1.7	0.0	1.7
2.5	Rate 145	6.9		8.3	(1.4)	0.0	(1.4)
2.6	Rate 170	32.6		35.7	(3.1)	0.7	(2.4)
2.7	Rate 200	173.9		170.8	3.1	(0.4)	2.7
2.	Total Contract Sales	271.1		283.3	(12.2)	0.4	(11.8)
Contract T-Service							
3.1	Rate 100	0.3		0.0	0.3	0.0	0.3
3.2	Rate 110	744.4		794.2	(49.8)	1.4	(48.4)
3.3	Rate 115	508.5		490.3	18.2	0.1	18.3
3.4	Rate 125	0.0		0.0	0.0	0.0	0.0
3.5	Rate 135	63.1		59.7	3.4	0.0	3.4
3.6	Rate 145	39.2		55.1	(15.9)	0.5	(15.4)
3.7	Rate 170	280.1		260.6	19.5	1.7	21.2
3.8	Rate 300	0.0		35.0	(35.0)	0.0	(35.0)
3.9	Rate 315	0.0		0.0	0.0	0.0	0.0
3.	Total Contract T-Service	1 635.6		1 694.9	(59.3)	3.7	(55.6)
4.	Total Contract Sales & T-Service	1 906.7		1 978.2	(71.5)	4.1	(67.4)
5.	Total	11 346.5		11 752.2	(405.7)	417.2	11.5

*Note: Weather normalization adjustments have been made to the 2017 Actual utilizing the 2017 Board Approved Budget Degree Days .

** Less than 50,000 m^3

The principal reasons for the variances contributing to the weather normalized increase of 11.5 10^6m^3 in the 2017 Actual over the 2017 Board Approved Budget are as follows:

1. The volumetric increase of 30.3 10^6m^3 in Rate 1 was due to a higher average use per customer totalling 25.3 10^6m^3 and favourable customer variance of 5.0 10^6m^3;

2. The volumetric increase of 48.9 10^6m^3 in Rate 6 was primarily due to a higher average use per customer totaling 67.3 $10^6m^{3,}$ and partially offset by unfavourable customer variance of 18.4 10^6m^3;

3. The volumetric decrease of 0.3 10^6m^3 in Rate 9 was due to a lower usage per station and loss of NGV stations;

4. The volumetric decrease for Contract Sales and T-Service of 67.4 10^6m^3 was due to decrease in the commercial sector of 5.4 10^6m^3 and industrial sector of 65.5 10^6m^3; partially offset by the increase in apartment sector of 0.8 10^6m^3 and rate 200 of 2.7 10^6m^3 .

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2017 ACTUAL AND 2017 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2017 Actual		Col. 2 2017 Board Approved Budget	Col. 3 2017 Actual Over (Under) 2017 Budget (1-2)	Col. 4 2017* Adjustments		Col. 5 2017 Actual Over (Under) 2017 Budget with Adjustments (3+4)
General Service								
1.1.1	Rate 1 - Sales	1 746.3		1 592.1	154.2	49.8		204.0
1.1.2	Rate 1 - T-Service	64.8		55.1	9.7	1.2		10.9
1.1	Total Rate 1	1 811.1		1 647.2	163.9	51.0		214.9
1.2.1	Rate 6 - Sales	842.6		807.0	35.6	34.3		69.9
1.2.2	Rate 6 - T-Service	242.0		171.2	70.8	8.4		79.2
1.2	Total Rate 6	1 084.6		978.2	106.4	42.7		149.1
1.3.1	Rate 9 - Sales	0.0	**	0.1	(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	0.0		0.1	(0.1)	0.0		(0.1)
1.	Total General Service Sales & T-Service	2 895.7		2 625.5	270.2	93.7		363.9
Contract Sales								
2.1	Rate 100	0.4		0.0	0.4	0.0		0.4
2.2	Rate 110	12.2		12.1	0.1	0.0	**	0.1
2.3	Rate 115	0.1		0.0	0.1	0.0		0.1
2.4	Rate 135	0.6		0.2	0.4	0.0		0.4
2.5	Rate 145	1.6		1.5	0.1	0.0	**	0.1
2.6	Rate 170	6.7		5.4	1.3	0.1		1.4
2.7	Rate 200	29.8		27.8	2.0	0.0		2.0
2.	Total Contract Sales	51.4		47.0	4.4	0.1		4.5
Contract T-Service								
3.1	Rate 100	0.2		0.0	0.2	0.0		0.2
3.2	Rate 110	47.7		35.0	12.7	0.0	**	12.7
3.3	Rate 115	14.4		8.0	6.4	0.0	**	6.4
3.4	Rate 125	11.1		11.7	(0.6)	0.0		(0.6)
3.5	Rate 135	5.4		2.4	3.0	0.0		3.0
3.6	Rate 145	3.0		2.1	0.9	0.0	**	0.9
3.7	Rate 170	7.8		3.3	4.5	0.0	**	4.5
3.8	Rate 300	0.1		0.2	(0.1)	0.0		(0.1)
3.9	Rate 315	0.2		0.0	0.2	0.0		0.2
3.	Total Contract T-Service	89.9		62.7	27.2	0.0		27.2
4.	Total Contract Sales & T-Service	141.3		109.7	31.6	0.1		31.7
5.	Total	3 037.0		2 735.2	301.8	93.8		395.6

* Note: Weather normalization adjustments have been made to the 2017 Actuals utilizing the 2017 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

1. Gas sales and transportation of gas revenues for the 2017 Test Year Budget were developed on the basis of EB-2016-0215 rates.

2. The principal reasons for the variance contributing to the increase of $301.8 million in the 2017 Actual compared to the 2017 Budget are as follows:

3. Gas Sales - increase of $194.1 Million

   The increase in gas sales revenue was mainly due to 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 $107.7 Million

   The increase in T-service revenue was mainly due to higher rate 6 volume and higher actual price than budgeted.

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

CUSTOMER METERS, VOLUMES AND REVENUES BY RATE CLASS
2017 ACTUAL

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes ($10^6 m^3$)	Col. 3 Revenues ($Millions)
General Service				
1.1.1	Rate 1 - Sales	1 902 271	4 526.7	1 746.3
1.1.2	Rate 1 - T-Service	87 761	212.5	64.8
1.1	Total Rate 1	1 990 032	4 739.2	1 811.1
1.2.1	Rate 6 - Sales	143 018	2 758.9	842.6
1.2.2	Rate 6 - T-Service	23 206	1 941.7	242.0
1.2	Total Rate 6	166 224	4 700.6	1 084.6
1.3.1	Rate 9 - Sales	3	0.0 **	0.0 ***
1.3.2	Rate 9 - T-Service	0	0.0	0.0
1.3	Total Rate 9	3	0.0	0.0
1.	Total General Service Sales & T-Service	2 156 259	9 439.8	2 895.7
Contract Sales				
2.1	Rate 100	1	0.9	0.4
2.2	Rate 110	40	53.8	12.2
2.3	Rate 115	0	0.1	0.1
2.4	Rate 135	3	2.9	0.6
2.5	Rate 145	4	6.9	1.6
2.6	Rate 170	4	32.6	6.7
2.7	Rate 200	1	173.9	29.8
2.	Total Contract Sales	53	271.1	51.4
Contract T-Service				
3.1	Rate 100	2	0.3	0.2
3.2	Rate 110	223	744.4	47.7
3.3	Rate 115	27	508.5	14.4
3.4	Rate 125	4	0.0 *	11.1
3.5	Rate 135	42	63.1	5.4
3.6	Rate 145	33	39.2	3.0
3.7	Rate 170	22	280.1	7.8
3.8	Rate 300	2	0.0	0.1
3.9	Rate 315	1	0.0	0.2
3.	Total Contract T-Service	356	1 635.6	89.9
4.	Total Contract Sales & T-Service	409	1 906.7	141.3
5.	Total	2 156 668	11 346.5	3 037.0

* There is no distribution volume for Rate 125 customers.

** Less than 50,000 m^3

*** Less than $50,000

DETAILS OF OTHER REVENUE AND OTHER INCOME
2017 ACTUAL AND 2017 BOARD APPROVED

Item No.		Col. 1 2017 Actual ($Millions)	Col. 2 2017 Board Approved Budget ($Millions)	Col. 3 2017 Actual Over/(Under) 2017 Board Approved ($Millions)
1.1	Service Charges & DPAC	12.8	12.3	0.5
1.2	Rental Revenue - NGV Program	1.3	1.1	0.2
1.3	Late Payment Penalties	10.3	10.1	0.2
1.4	Dow Moore Recovery	0.3	0.3	-
1.5	Transactional Services (net)	12.0	12.0	-
1.6	Miscellaneous and Other Income	0.3	1.6	(1.3)
1.7	Open Bill Revenue	5.4	5.4	-
1.8	Total Other Revenue	42.4	42.8	(0.4)

COST OF SERVICE (INCLUDING CUSTOMER CARE & CIS)
2017 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	1,640.8	27.2	1,668.0
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	431.5	-	431.5
3.	Depreciation and amortization expense	301.3	-	301.3
4.	Fixed financing costs	2.8	-	2.8
5.	Municipal and other taxes	44.6	-	44.6
6.	Operating costs	2,421.0	27.2	2,448.2
7.	Income tax expense			1.0
8.	Cost of service			2,449.2

EXPLANATION OF ADJUSTMENTS TO UTILITY COSTS
2017 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
1.	27.2	Gas costs Adjustment required to gas costs to reflect normal weather.

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 ACTUAL

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	424.8	424.8	
	Add			
2.	Depreciation and amortization	301.3	301.3	
3.	Accrual based pension and OPEB costs	24.7	24.7	
4.	Other non-deductible items	0.4	0.4	
5.	Total Add Back	326.4	326.4	
6.	Sub-total	751.2	751.2	
	Deduct			
7.	Capital cost allowance	360.2	360.2	
8.	Items capitalized for regulatory purposes	72.2	72.2	
9.	Deduction for "grossed up" Part VI.1 tax	3.2	3.2	
10.	Amortization of share/debenture issue expense	4.7	4.7	
11.	Amortization of cumulative eligible capital	-	-	
12.	Amortization of C.D.E. and C.O.G.P.E	0.2	0.2	
13.	Site Restoration Costs adjustment	77.5	77.5	
14.	Cash based pension and OPEB costs	50.3	50.3	
15.	Total Deduction	568.3	568.3	
16.	Taxable income	182.9	182.9	
17.	Income tax rates	15.00%	11.50%	
18.	Provision	27.4	21.0	48.4
19.	Part VI.1 tax			0.9
20.	Total taxes excluding interest shield			49.3
	Tax shield on interest expense			
21.	Rate base	6,465.2		
22.	Return component of debt	2.82%		
23.	Interest expense	182.4		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(48.3)
26.	Total utility income taxes			1.0

COST OF SERVICE
2017 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	1,991.1	(350.3)	1,640.8
2.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	466.1	(34.6)	431.5
3.	Depreciation	302.1	(0.8)	301.3
4.	Amortization	22.5	(22.5)	-
5.	Depreciation and amortization	324.6	(23.3)	301.3
6.	Fixed financing costs	2.8	-	2.8
7.	Municipal and other taxes	44.8	(0.2)	44.6
8.	Capital taxes	-	-	-
9.	Municipal and other taxes	44.8	(0.2)	44.6
10.	Interest on long-term debt	175.3	(175.3)	-
11.	Amortization of preference share issue costs and debt discount and expense	4.2	(4.2)	-
				-
12.	Interest and financing amortization	179.5	(179.5)	-
13.	Interest on short-term debt	10.1	(10.1)	-
14.	Interest due affiliates	26.8	(26.8)	-
				-
15.	Other interest expense	36.9	(36.9)	-
16.	Total operating costs	3,045.8	(624.8)	2,421.0
17.	Current taxes	5.2	(5.2)	-
18.	Deferred taxes	(20.0)	20.0	-
19.	Income tax expense	(14.8)	14.8	-
20.	Cost of service	3,031.0	(610.0)	2,421.0

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2017 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation	
1	(350.3)	Gas costs	
		US GAAP adjustment elimination for deferral & variance clearance recognition.	3.0
		Removal of Cap and Trade costs.	(353.3)
			(350.3)
2.	(34.6)	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.	0.6
		To eliminate donations (EBRO 490).	(0.8)
		To eliminate non-utility costs and expenses relating to the support of the ABC T-service program.	(0.7)
		To eliminate Electric CDM net benefit. Ratepayer amount was transferred to the 2017 EPESDA and shareholder amount is eliminated from utility results.	0.7
		To eliminate EGD/Union Amalgamation transaction costs	(0.2)
		US GAAP adjustment elimination for deferral & variance clearance recognition.	(8.7)
		To eliminate Corporate Cost allocations above RCAM amount.	(1.6)
		To eliminate earnings sharing recorded in the financial statements.	(23.9)
			(34.6)
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.	
7.	(0.2)	Municipal and other taxes	
		Removal of municipal taxes related to shared assets (RP-2002-0133).	

EXPLANATION OF ADJUSTMENTS TO EGDI CORPORATE
COSTS AND EXPENSES
2017 ACTUAL

Line No. Adjusted	Adjustment Increase (Decrease) ($Millions)	Explanation
10.	(175.3)	Interest on long-term debt Expense of capital.
11.	(4.2)	Amortization of preference share issue costs and debt discount and expense Expense of capital.
13.	(10.1)	Interest on short-term debt Expense of capital.
14.	(26.8)	Interest due affiliates To eliminate non-utility inter-company interest expense from the financing transaction (EBO 179-16).
17.	(5.2)	Income taxes - current Income tax expense related to corporate earnings.
18.	20.0	Income taxes - deferred Income tax expense related to corporate earnings.

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2017 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 F2017	UCC Carry Forward
1	1,581,943,554	-	-	-	4.00%	(63,277,742)	1,518,665,812
51	2,998,144,246	367,710,484	-	183,855,242	6.00%	(190,919,969)	3,174,934,761
2	92,562,796	-	(626,672)	(313,336)	6.00%	(5,534,968)	86,401,156
6	5,951	-	-	-	10.00%	(595)	5,356
8	18,914,446	2,855,252	-	1,427,626	20.00%	(4,068,414)	17,701,284
10	20,442,326	8,522,248	(360,126)	4,081,061	30.00%	(7,357,016)	21,247,432
12	53,256,783	27,536,313	-	13,768,157	100.00%	(67,024,940)	13,768,157
12	-	-	-	-	-	-	-
17	23,200	-	-	-	8.00%	(1,856)	21,344
38	3,880,459	112,308	(228,014)	(57,853)	30.00%	(1,146,782)	2,617,971
41	44,554,211	5,742,027	-	2,871,014	25.00%	(11,856,306)	38,439,932
13	268,493	-	-	-	-	(268,493)	-
3	192,809	-	-	-	5.00%	(9,641)	183,169
45	44,815	-	-	-	45.00%	(20,167)	24,648
50	9,227,582	5,743,468	-	2,871,734	55.00%	(6,654,624)	8,316,426
14.1	-	40,391,417	-	-	7.00%	(2,827,399)	37,564,018
Total	4,823,461,671	458,613,517	(1,214,812)	208,503,644		(360,968,911)	4,919,891,464

Non-utility and shared asset eliminations	758,942
Utility Federal CCA	(360,209,969)

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 F2017	UCC Carry Forward
1	1,581,943,554	-	-	-	4.00%	(63,277,742)	1,518,665,812
51	2,998,144,246	367,710,484	-	183,855,242	6.00%	(190,919,969)	3,174,934,761
2	92,562,796	-	(626,672)	(313,336)	6.00%	(5,534,968)	86,401,156
6	5,951	-	-	-	10.00%	(595)	5,356
8	18,914,446	2,855,252	-	1,427,626	20.00%	(4,068,414)	17,701,284
10	20,442,326	8,522,248	(360,126)	4,081,061	30.00%	(7,357,016)	21,247,432
12	53,256,783	27,536,313	-	13,768,157	100.00%	(67,024,940)	13,768,157
12	-	-	-	-	-	-	-
17	23,200	-	-	-	8.00%	(1,856)	21,344
38	3,880,459	112,308	(228,014)	(57,853)	30.00%	(1,146,782)	2,617,971
41	44,554,211	5,742,027	-	2,871,014	25.00%	(11,856,306)	38,439,932
13	268,493	-	-	-	-	(268,493)	-
3	192,809	-	-	-	5.00%	(9,640)	183,169
45	44,815	-	-	-	45.00%	(20,167)	24,648
50	9,227,582	5,743,468	-	2,871,734	55.00%	(6,654,624)	8,316,426
14.1	-	40,391,417	-	-	7.00%	(2,827,399)	37,564,018
Total	4,823,461,671	458,613,517	(1,214,812)	208,503,644		(360,968,911)	4,919,891,465

Non-utility and shared asset eliminations	758,942
Utility Provincial CCA and UCC	(360,209,969)

2017 UTILITY O&M

Line No.	Particulars (in millions)	Actuals 2017	IR 2017	Actual Under/(Over)
1	Total Compensation	223.9	235.1	11.3
2	Employee Training and Development	4.2	5.0	0.7
3	Materials and Supplies	5.3	5.5	0.2
4	Outside Services	82.5	94.0	11.5
5	Consulting	2.6	5.3	2.7
6	Repairs and Maintenance	1.7	2.5	0.9
7	Fleet	3.1	11.0	7.9
8	Rents and Leases	4.9	8.1	3.2
9	Telecommunications	0.0	4.0	4.0
10	Travel and Other Business Expenses	1.8	5.3	3.5
11	Memberships	5.2	5.4	0.2
12	Claims, Damages and Legal Fees	0.4	1.0	0.6
13	Interest on Security Deposits	0.6	2.6	2.0
14	Provision for Uncollectibles	5.4	9.8	4.4
15	Natural Gas Vehicles (NGV)	0.8	-	(0.8)
16	Legal Fees	2.8	3.0	0.1
17	Audit Fees	0.8	1.7	0.9
18	Other	1.2	(8.5)	(9.6)
19	Internal Allocations and Recoveries	(14.0)	(31.1)	(17.1)
20	Capitalization (A&G)	(36.8)	(38.3)	(1.5)
21	Capitalization	(85.1)	(83.2)	2.0
22	Regulatory Eliminations	(1.7)	(3.4)	(1.7)
23	Other O&M Subtotal	209.5	234.9	25.4
24	Customer Care/CIS Service Charges	85.4	105.3	19.9
25	Pensions and OPEB	24.7	24.7	(0.0)
26	RCAM	49.6	34.8	(14.8)
27	Demand Side Management Programs (DSM)	62.9	62.9	(0.0)
28	Conservation Services	(0.7)	-	0.7
29	Total Net Utility O&M Expense before Eliminations	431.5	462.7	31.2

EXPLANATION OF MAJOR CHANGES
ACTUAL 2017 O&M EXPENSES COMPARED TO OEB APPROVED 2017 O&M EXPENSES

1 Decrease in Total Compensation due to labour reductions partially offset by severance costs.

4 Decrease in Outside Services mainly due to capital recoveries for contractors which is budgeted in Internal Allocations and Recoveries while actuals are recognized in the Outside Services category.

7 Decrease in Fleet is mainly due to capital allocations which is budgeted in Internal Allocations and Recoveries while actuals are recognized in the Fleet category.

9 Decrease in Telecommunications due to the centralization of telecommunication costs under Enbridge Inc.

14 Decrease in Provision for Uncollectibles due to continued improvements in collections.

18 Increase in Other mainly due to reduction in IR budget of $13.6M based on OEB decision.

19 Decrease in Internal Allocations and Recoveries mainly due Fleet and Outside Service. Actual allocations and recoveries are recognized in the respective cost categories while the budget resides in Internal Allocations and Recoveries.

24 Decrease in Customer Care/CIS Service Charges due to reduced CIS support costs, improved collections, postage savings from higher number of customers on e-bill, and system improvements reducing manual work.

26 Increase in RCAM is due to the centralization of IT and HR services to Enbridge Inc.

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN (INCLUDING CUSTOMER CARE & CIS)
2017 ACTUAL

Line No.		Col. 1 Principal	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component	Col. 5 (col 1x col 3) Interest & pref share Expense
		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	3,677.3	56.88	4.86	2.764	178.7
2.	Short-Term Debt	360.4	5.57	1.05	0.058	3.8
3.		4,037.7	62.45		2.822	
4.	Preference Shares	100.0	1.55	2.32	0.036	2.3
						184.8
5.	Common Equity	2,327.5	36.00	8.78	3.161	
6.		6,465.2	100.00		6.019	
7.	Rate Base	($Millions)			6,465.2	
8.	Utility Income	($Millions)			423.8	
9.	Indicated Rate of Return				6.555	
10.	Sufficiency in Rate of Return				0.536	
11.	Net Sufficiency	($Millions)			34.7	
12.	Gross Sufficiency	($Millions)			47.1	
13.	Revenue at Existing Rates	($Millions)			2,830.6	
14.	Allowed Revenue	($Millions)			2,783.5	
15.	Gross Revenue Sufficiency	($Millions)			47.1	
	Common Equity					
16.	Allowed Rate of Return				8.78	
17.	Earnings on Common Equity				10.27	
18.	Sufficiency in Common Equity Return				1.49	

UTILITY INCOME (INCLUDING CIS & CUSTOMER CARE)
2017 ACTUAL

Line No.		Col. 1 Utility Income Incl. CIS & Customer Care
		($Millions)
1.	Gas sales	2,503.4
2.	Transportation of gas	308.2
3.	Transmission, compression and storage revenue	19.0
4.	Other operating revenue	42.1
5.	Interest and property rental	-
6.	Other income	0.3
7.	Total operating revenue (Ex. B-3-1-pg.1)	2,873.0
8.	Gas costs	1,668.0
9.	Operation and maintenance	431.5
10.	Depreciation and amortization expense	301.3
11.	Fixed financing costs	2.8
12.	Municipal and other taxes	44.6
13.	Interest and financing amortization expense	-
14.	Other interest expense	-
15.	Cost of service (Ex. B-4-1-pg.1)	2,448.2
16.	Utility income before income taxes	424.8
17.	Income tax expense (Ex. B-4-1-pg.3)	1.0
18.	Utility income	423.8

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
2017 ACTUAL

Line No.		Col. 1 Average of Monthly Averages ($Millions)	Col. 2	Col. 3 Carrying Cost ($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	3,709.2		180.2
2.	Unamortized Finance Costs	(31.9)		-
3.	(Profit)/Loss on Redemption	-		-
4.		3,677.3		180.2
5.	Calculated Cost Rate		4.86%	
	Short-Term Debt			
6.	Calculated Cost Rate		1.05%	
	Preference Shares			
7.	Preference Share Summary	100.0		2.3
8.	Unamortized Finance Costs	-		-
9.	(Profit)/Loss on Redemption	-		-
10.		100.0		2.3
11.	Calculated Cost Rate		2.32%	
	Common Equity			
12.	Board Formula ROE		8.78%	

SUMMARY STATEMENT OF PRINCIPAL
AND CARRYING COST OF
TERM DEBT
2017 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	191.7	5.220%	10.0
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	170.0	4.436%	7.5
20.	3.31%	September 11, 2025	400.0	3.619%	14.5
21.	2.50%	August 5, 2026	300.0	3.423%	10.3
22.	3.51%	November 29, 2047	37.5	3.527%	1.3
23.			3,624.2		171.8
Long-Term Debentures					
24.	9.85%	December 2, 2024	85.0	9.910%	8.4
25.			85.0		8.4
26.	Total Term Debt		3,709.2		180.2

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
2017 ACTUAL

Line No.		Col. 1 Unamortized Debt Discount and Expense
		($Millions)
1.	January 1	33.7
2.	January 31	33.4
3.	February	33.0
4.	March	32.7
5.	April	32.4
6.	May	32.0
7.	June	31.7
8.	July	31.3
9.	August	31.0
10.	September	30.7
11.	October	30.3
12.	November	31.5
13.	December	31.2
14.	Average of Monthly Averages	31.9

DEFERRAL & VARIANCE ACCOUNTS
REQUESTED FOR CLEARANCE JANUARY 1, 2019

1. The Company requests approval for clearance of the Deferral and Variance Account balances shown in the Table on page 3, Columns 3 and 4 of this Exhibit, commencing January 1, 2019. The balances requested for clearance total approximately $5.0 million, which is the combination of principal and interest amounts shown in Columns 3 and 4.

2. 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, with the exception of the ESMDA, for which details are included in the B series of exhibits.

3. 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, 2018 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.

4. The Company notes that at this time it is not requesting clearance of the balances recorded within the 2015, 2016, and 2017 DSM related deferral accounts (DSMVA, LRAM, and DSMIDA). Any amounts to be cleared in relation to DSM related accounts will be reviewed and approved through separate DSM proceedings.

5. The 2017 Manufactured Gas Plant Deferral Account ("MGPDA") is also not being requested for clearance at this time. The December 31, 2017 MGPDA principal

and interest balances were transferred to corresponding 2018 accounts in accordance with the account descriptions approved within EB-2017-0086. Clearance of amounts recorded in the MGPDA will be requested in a future proceeding.

6. Finally, the Company is also not requesting clearance of the balances recorded within the 2016 and 2017 Cap and Trade related deferral accounts (GGEIDA, GGECOCRVA, and GGECOFRVA) as part of this proceeding. Any amounts to be cleared in relation to Cap and Trade related accounts will be reviewed and approved through Cap and Trade Compliance Plan proceedings.

7. A 2018 CDNSADA balance is being requested for clearance within this proceeding, as agreed within the Board approved EB-2017-0086 (2018 Rate Adjustment) Amended Settlement Agreement. Evidence with respect to the 2018 CDNSADA balance sought for disposition and the associated allocation methodology can be found at Exhibit C, Tab 1, Schedule 12 and Exhibit C, Tab 2, Schedule 1.

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

			Col. 1	Col. 2	Col. 3	Col. 4
			Actual at May 31, 2018		Forecast for clearance at January 1, 2019	
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 Managment V/A	2017 DSMVA	(1,277.1)	(8.8)	-	- [1]
2.	Demand Side Managment V/A	2016 DSMVA	(704.0)	(13.3)	-	- [1]
3.	Demand Side Managment V/A	2015 DSMVA	825.5	26.8	-	- [1]
4.	Lost Revenue Adjustment Mechanism	2017 LRAM	-	-	-	- [1]
5.	Lost Revenue Adjustment Mechanism	2016 LRAM	(100.0)	(0.7)	-	- [1]
6.	Lost Revenue Adjustment Mechanism	2015 LRAM	(72.3)	(1.4)	-	- [1]
7.	Demand Side Managment Incentive D/A	2016 DSMIDA	2,893.5	23.6	-	- [1]
8.	Demand Side Managment Incentive D/A	2015 DSMIDA	6,068.6	120.3	-	- [1]
9.	Deferred Rebate Account	2017 DRA	1,834.0	36.7	1,834.0	57.0 [2]
10.	Gas Distribution Access Rule Impact D/A	2017 GDARIDA	-	-	265.9	- [3]
11.	Manufactured Gas Plant D/A	2018 MGPDA	618.9	50.8	-	- [4]
12.	Electric Program Earnings Sharing D/A	2017 EPESDA	(680.2)	(4.7)	(680.2)	(12.4) [5]
13.	Average Use True-Up V/A	2017 AUTUVA	(4,035.7)	(27.8)	(4,035.7)	(72.6) [6]
14.	Earnings Sharing Mechanism Deferral Account	2017 ESMDA	(23,700.0)	(163.5)	(23,550.0)	(423.4) [7]
15.	Customer Care CIS Rate Smoothing D/A	2017 CCCISRSDA	(2,785.3)	(35.8)	-	(59.6) [8]
16.	Customer Care CIS Rate Smoothing D/A	2016 CCCISRSDA	(779.9)	(7.6)	-	(14.6) [8]
17.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	11.0	-	20.8 [8]
18.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	28.7	-	53.9 [8]
19.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	45.4	-	85.3 [8]
20.	Transition Impact of Accounting Changes D/A	2018 TIACDA	66,537.0	-	4,435.8	- [9]
21.	Post-Retirement True-Up V/A	2017 PTUVA	(4,299.2)	(47.1)	(4,299.2)	(94.7) [10]
22.	Constant Dollar Net Salvage Adjustment D/A	2018 CDNSADA	18,910.1	-	6,468.3	- [11]
23.	Greenhouse Gas Emissions Impact D/A	2016 GGEIDA	939.8	22.1	-	- [12]
24.	Greenhouse Gas Emissions Impact D/A	2017 GGEIDA	2,176.1	27.6	-	- [12]
25.	OEB Cost Assessment V/A	2017 OEBCAVA	2,649.9	35.2	2,649.9	64.6 [13]
26.	Greenhouse Gas Emissions Compliance Obligation-Customer Related V/A	2017 GGECOCRVA	11,471.8	156.2	-	- [12]
27.	Dawn Access Costs D/A	2017 DACDA	-	-	(910.7)	- [14]
28.	Total non commodity Related Accounts		85,177.6	273.7	(17,821.9)	(395.7)
	Commodity Related Accounts					
29.	Transactional Services D/A	2017 TSDA	1,206.4	7.5	1,206.4	20.8 [15]
30.	Storage and Transportation D/A	2017 S&TDA	22,654.8	280.3	22,654.8	530.2 [15]
31.	Unaccounted for Gas V/A	2017 UAFVA	(1,129.9)	(21.9)	(1,129.9)	(34.5) [16]
32.	Total commodity related accounts		22,731.3	265.9	22,731.3	516.5
33.	Total Deferral and Variance Accounts		107,908.9	539.6	4,909.4	120.8

Notes:

1. The clearance of DSM related accounts will be determined through separate DSM proceedings.
2. DRA evidence is found at Exhibit C, Tab 1, Schedule 7.
3. The clearance amount associated with the 2017 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 6.
4. Clearance of the balance that was recorded in 2017 MGPDA is not being requested at this time. As was approved in the EB-2017-0086 proceeding, the balance in the 2017 MGPDA was transferred to the 2018 MGPDA.
5. EPESDA evidence is found at Exhibit C, Tab 1, Schedule 10.
6. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 4.
7. Evidence within the B-series of exhibits provides details of Enbridge's 2017 utility results and 2017 earnings sharing calculation.
8. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 9.
9. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 8.
10. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
11. CDNSADA evidence is found at Exhibit C, Tab 1, Schedule 12 and Exhibit C, Tab 2, Schedule 1.
12. Clearance of Cap and Trade related accounts (GGEIDA, GGECOCRVA, & GGECOFRVA) will be determined through Cap and Trade compliance plan proceedings.
13. OEBCAVA evidence is found at Exhibit C, Tab 1, Schedule 11.
14. DACDA evidence is found at Exhibit C, Tab 1, Schedule 13 and Exhibit C, Tab 2, Schedule 1.
15. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 2.
16. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 3.

2017 STORAGE & TRANSPORTATION DEFERRAL ACCOUNT, 2017 TRANSACTIONAL SERVICES DEFERRAL ACCOUNT, REQUESTED FOR CLEARANCE JANUARY 1, 2019

2017 Storage and Transportation Deferral Account (2017 S&TDA)

1. The purpose of the 2017 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 2017 S&TDA that the Company is proposing to collect from customers is $22.6 million plus interest.

4. The primary driver for the balance in the 2017 S&TDA is due to an increase in Union M12 tolls, approved by the Ontario Energy Board and effective January 1, 2017 compared to the January 1, 2016 tolls that the 2017 gas cost budget was based upon. For a detailed breakdown of the variance please see Attachment 1.

2017 Transactional Services Deferral Account (2017 TSDA)

5. 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: K. Lakatos-Hayward
D. Small

6. 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.

7. 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. This implies an embedded Transactional Service revenue forecast of $13.2 million. As the ratepayer share is not guaranteed, 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.

8. During 2017 the Company was able to generate a total of $11.9 million in net Transactional Services revenue through a combination of Storage and Transportation Optimization. Attachment 2 provides a breakdown of Transactional Services revenue by type of transaction, and sets out the details of the amount, $1.2 million proposed to be collected from customers through the disposition of the 2017 TSDA. For comparison purposes the schedule also includes amounts recorded in the applicable TSDA accounts for years 2016, 2015 and 2014.

9. The transactions that Enbridge entered into in 2017 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.

Breakdown of the 2017 Storage and Transportation Deferral Account ("2017 S&TDA)

Item #	Contracted Union Capacity	Column 1 Daily Contract Demand Volume - GJ's	Column 2 Monthly Demand Toll Assumed in 2017 Budget - $/GJ	Forecasted Annual Cost - $ (millions)		Column 3 Monthly Demand Toll Effective January 1, 2017 - $/GJ	Column 4 Annual Cost - $ (millions)	Column 5 Balance in the 2017 S&TDA
1.1	Union Gas Dawn to Lisgar	67,929	2.421	2.0		2.865	2.3	
1.2.1	Union Gas Dawn to Parkway	2,527,173	2.883	87.4		3.402	103.2	
1.2.2	Union Gas Dawn to Parkway	190,000	2.883	1.1	(1)	3.402	1.3	
1.3	Union Gas Dawn to Parkway - M12X	200,000	3.602	8.6		4.239	10.2	
1.4	Union Gas Parkway to Dawn - C1	236,586	0.719	2.0		0.837	2.4	
1.5	Union Gas F24 T	85,000	0.069	0.1		0.069	0.1	
1.	Union Transmission Costs			101.3	(2)		119.4	18.2
2.	Cap and Trade costs			-			1.9	1.9
3	Third Party Market Based Storage			16.8	(3)		19.4	2.6
4.	EGD's share of Union's Disposition of their Deferral/Earnings Sharing Adjustment - M12			-			(0.7)	(0.7)
5.	Total			118.0			140.0	21.9

note 1 - Contract effective November 1, 2017
note 2 - see EB-2016-0215, Exhibit D1, Tab 2, Schedule 6, Item #2, Column 1 - excluding impact of Dawn T-Service
note 3 - see EB-2016-0215, Exhibit D1, Tab 2, Schedule 5, Item #1.4, Column 1

Item #		2017 Transactional Services Revenue	2016 Transactional Services Revenue	2015 Transactional Services Revenue	2014 Transactional Services Revenue
		$ 000's	$ 000's	$ 000's	$ 000's
1.0	Storage Optimization	1,550.1	7,277.2	517.4	1,703.4
2.0	Transportation Optimization	10,393.3	10,463.5	22,727.1	12,910.3
3.0	Transactional Services Revenue	11,943.5	17,740.6	23,244.6	14,613.7
4.0	Ratepayer Portion of TS	10,749.1	15,966.6	20,920.1	13,152.4
5.0	Less Amount Included in Rates	12,000.0	12,000.0	12,000.0	12,000.0
6.0	TSDA sub-total	(1,250.9)	3,966.6	8,920.1	1,152.4
7.0	ETT Revenue - Rider H	44.5	69.7	154.7	104.4
8.0	TSDA Total	(1,206.4)	4,036.3	9,074.8	1,256.7

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 2017 variance relative to historical Unaccounted-For Gas ("UAF") volumes.

2. UAF 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. In the Company's UAF study filed in 2013 (EB-2011-0354, Exhibit D2, Tab 6, Schedule 1), results identified meter uncertainty as the main source of UAF. Custody transfer meters, residential diaphragm meters, rotary meters and other meters are required by Measurement Canada to be within specified limits of error, depending on the type of meter. 2017 UAF is within all tolerance levels, at 0.80% of total 2017 throughput volumes.

4. The 2017 level of UAF was determined to be 93,077 10^3m^3. The variance of 5,202 10^3m^3, which is the difference between actual UAF volume and the forecast UAF volume of 98,279 10^3m^3, underpins the $1.1M payable balance that is captured in the UAFVA.

Witnesses: K. Lakatos-Hayward
J. Shem

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 2017 that would have contributed to a lower UAF than recently experienced.

6. As shown in Tables 1 and 2 in the following pages, UAF has been quite volatile over the years, showing some stability from 2010-2012, and followed by higher levels especially in 2014 and 2016. The 2017 UAF level falls within the 95% confidence interval, bounded by (14,946) 10^3m^3 and 157,801 10^3m^3.

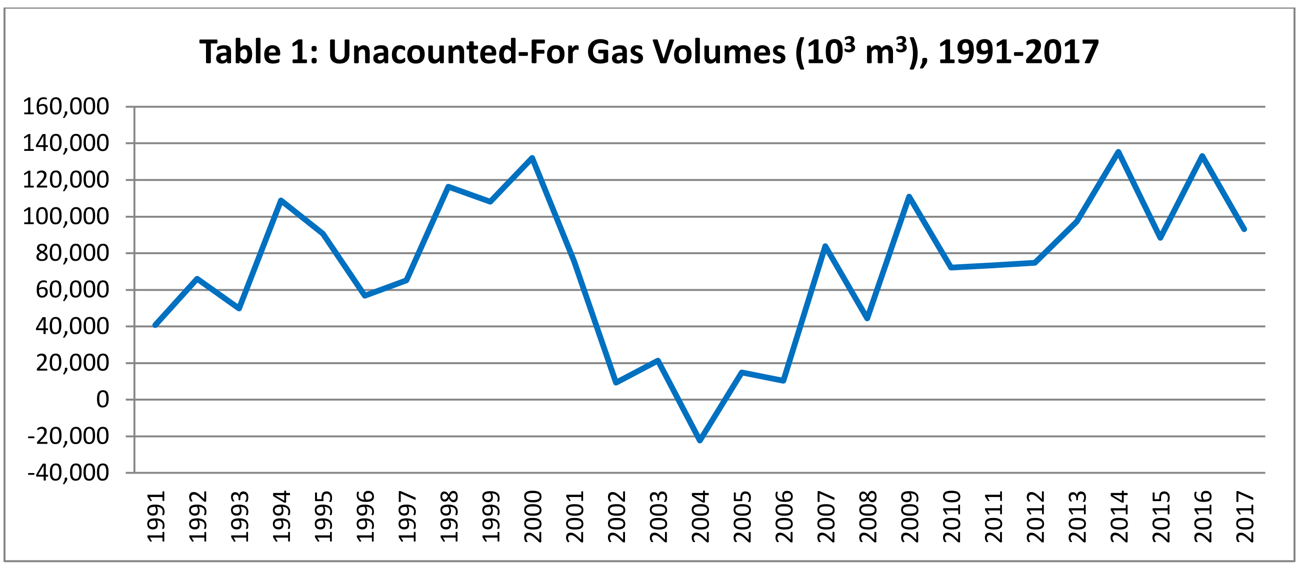

Table 2

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
2016	133,112
2017	93,077
	1991-2016
Standard Deviation	41,929
Mean	71,427
Lower bound*	-14,946
Upper bound*	157,801

*95% confidence interval with 25 degrees of freedom (number of observations-1)

Witnesses: K. Lakatos-Hayward
J. Shem

2017 ACTUAL AVERAGE USE TRUE-UP VARIANCE ACCOUNT

1. The purpose of this evidence is to provide information in support of the 2017 Average Use True-up Variance Account ("AUTUVA") balance.

2. Table 1 of Appendix A details the calculations that result in the amount of $4.04 million that will constitute a refund to ratepayers. The collection is attributable to actual Rate 1 (residential) and Rate 6 average (apartment, small commercial and industrial) uses being higher than 2017 forecast levels.

3. Higher weather-normalized average use is primarily attributable to better economic conditions in 2017 than were forecast. Even though residential gas prices were slightly higher than forecast; stronger GDP growth and higher employment levels in the province supported stronger economic conditions which led to higher consumption for both Rate 1 and Rate 6.

4. The purpose of the AUTUVA is to record or "true-up" the revenue impact (exclusive of gas costs) of the normalized volumetric difference between the forecast of average use per customers in Rate 1 and Rate 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 the impact used in the derivation of the Lost Revenue Adjustment Mechanism ("LRAM").

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 2017 DSM activities will not be available until a later date, the 2017 Board Approved Budget DSM volumes are used as an estimate of 2017 actuals. Without the exclusion of a DSM volumetric variance in the AUTUVA calculation, the impacts of DSM are inherently included. As a result, 2017 LRAM amounts which will be filed at a later date, will exclude the impact of Rate 1 and Rate 6 customers.

TABLE 1

2017 ACTUAL AVERAGE USE TRUE UP VARIANCE ACCOUNT

Rate Class	Col. 1 2017 Budget Annual Use (m^3)	Col. 2 2017 Normalized Actual Annual Use (m^3)	Col. 3 =Col. 2-1 Normalized Usage Variance (m^3)	Col. 4 Budget Customer Meters	Col. 5 =Col. 3*4 Normalized Volumetric Variance (10^6m^3)	Col. 6 2017 DSM Budget (10^6m^3)	Col. 7 2017 DSM Actual (10^6m^3)	Col. 8 =Col. 7-6 DSM Volumetric Variance (10^6m^3)	Col. 9 =Col. 5-8 Normalized Volumetric Variance Excluding DSM (10^6m^3)	Unit Rate of the Revenue Impact, exclusive of gas costs Col. 10 Unit Rate ($/$m^3$)	Col. 11 =Col. 9*10 AUTUVA: Revenue Impact, Exclusive of Gas Costs - ($ millions)
1	2,472	2,485	13	1,987,028	25.3	(5.5)	(5.5)	0.0	25.3	0.06	1.54
6	29,058	29,462	404	166,479	67.3	(17.0)	(17.0)	0.0	67.3	0.04	2.50
Total					92.7	(22.5)	(22.5)	0.0	92.7		4.04

2017 POST-RETIREMENT TRUE-UP VARIANCE ACCOUNT ("PTUVA")

1. In accordance with the EB-2016-0215 Final Accounting Order, page 22, the purpose of PTUVA is to record the differences between the 2017 forecast pension and post-employment benefit ("OPEB") expenses of $24.7 million and the actual 2017 pension and OPEB expenses (both determined on an accrual basis).

2. As of December 31, 2017 the actual pension and OPEB expense was $25.1 million, as calculated by Mercer. A breakdown of the $25.1 million is as follows:

	$ million
Registered Pension Plan	17.9
Supplementary Executive Retirement Plan	0.0
Senior Supplementary Executive Retirement Plan	(0.1)
Supplementary Pension Plan	1.5
Defined contribution	0.7
Total pension expense	20.0
OPEB expense	5.1
Total pension and OPEB expense	25.1

3. Please refer to Appendix 1 for extracts of the 2017 Final Accounting Mercer Reports that support the figures above.

4. Therefore, the PTUVA balance that relates to the 2017 year is a $0.4 million recovery, which is the difference between the Board-approved forecast of $24.7 million and the actual expense of $25.1 million.

5. As was agreed in Enbridge's 2013 Rate Application (EB-2011-0354) Settlement Agreement (p. 20), the maximum clearance from the PTUVA (credit or debit) in any

Witnesses: R. Rutitis
C. Tuckwell

one year is $5 million. Any remaining balance is to be carried forward to the following year, so that large variances can be cleared over time (smoothed). This treatment for the PTUVA has remained in place since 2013, and is reflected in the EB-2016-0215 approved 2017 PTUVA.

6. In 2016, the PTUVA balance was a $9.7 million credit (refund). In accordance with the treatment of this account as described above, only $5 million was cleared (refunded) from the 2016 PTUVA. The remaining PTUVA balance that relates to the 2016 year is a $4.7 million refund and this was approved to be transferred to the 2017 PTUVA balance.

7. In this proceeding, the Company is requesting to refund $4.3 million in accordance with the EB-2016-0215B approved variance account scope. A breakdown of the $4.3 million is as follows:

	$ million
PTUVA balance that relates to the 2017 year	0.4
Remaining 2016 PTUVA balance that was transferred to the 2017 PTUVA balance	(4.7)
Total 2017 PTUVA balance	(4.3)

Witnesses: R. Rutitis
C. Tuckwell

Breakdown of the actual pension and post-employment benefit ("OPEB") expense as of December 31, 2017, as calculated by Mercer:

	$ million	Reference
Registered Pension Plan - Enbridge Gas Distribution Inc.	$18.1	Page 2
Registered Pension Plan - Enbridge Inc.	(0.2)	Page 3
Registered Pension Plan	17.9	
Supplementary Executive Retirement Plan	0.0	Page 4
Senior Supplementary Executive Retirement Plan	(0.1)	Page 4
Supplementary Pension Plan	1.5	Page 5
Defined contribution	0.7	Page 6
Total pension expense	20.0	
OPEB expense	5.1	Page 7
Total pension and OPEB expense	25.1	

MERCER

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2017
Final US GAAP - January 15, 2018
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)	(282,313,500)	(5,664,200)	(3,060,100)	(291,037,800)
Accumulated other comprehensive income (loss)	(282,313,500)	(5,664,200)	(3,060,100)	(291,037,800)
Accumulated contributions in excess of net periodic benefit cost	231,673,000	974,500	(1,001,300)	231,646,200
Net asset (obligation) recognized in statement of financial position	(50,640,500)	(4,689,700)	(4,061,400)	(59,391,600)
F. Components of net periodic benefit cost				
Service cost	30,460,200	962,700	861,100	32,284,000
Interest cost	33,614,100	664,200	439,200	34,717,500
Expected return on plan assets	(60,599,400)	(983,100)	(611,600)	(62,194,100)
Amortization of initial net obligation (asset)	-	-	-	-
Amortization of prior service cost	-	-	-	-
Amortization of net (gain) loss	14,661,800	285,400	139,400	15,086,600
Net periodic benefit cost	18,136,700	929,200	828,100	19,894,000
Headcounts for expense[1]				
EGD RPP - DB service cost provision	1,988	81	78	2,147
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	(491,000)	159,400	371,600	40,000
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)	(14,661,800)	(285,400)	(139,400)	(15,086,600)
Total recognized in other comprehensive loss (income)	(15,152,800)	(126,000)	232,200	(15,046,600)
Total recognized in net periodic benefit and other comprehensive loss (income)	2,983,900	803,200	1,060,300	4,847,400
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)	(13,216,300)	(265,800)	(117,600)	(13,599,700)

[1] Note the 2017 expense is based on headcount as at December 31, 2015

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2017

Final US GAAP - January 15, 2018

Enbridge Inc. Pension Plans - EI RPP

	Enbridge Inc.	Enbridge Employee Services Canada 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 statements of financial position											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	-	-	-	-	-	-	-	-	-	-	-
Net gain (loss)	(37,732,800)	(164,654,900)	(844,300)	(1,371,400)	(276,200)	(7,479,100)	(1,926,900)	(62,900)	-	(2,320,300)	(216,668,800)
Accumulated other comprehensive income (loss)	(37,732,800)	(164,654,900)	(844,300)	(1,371,400)	(276,200)	(7,479,100)	(1,926,900)	(62,900)	-	(2,320,300)	(216,668,800)
Accumulated contributions in excess of net periodic benefit cost	16,963,500	107,543,500	1,816,200	2,460,000	2,490,200	(428,200)	3,489,500	83,200	-	465,600	134,883,500
Net asset (obligation) recognized in statement of financial position	(20,769,300)	(57,111,400)	971,900	1,088,600	2,214,000	(7,907,300)	1,562,600	20,300	-	(1,854,700)	(81,785,300)
F. Components of net periodic benefit cost											
Service cost	18,314,000	57,131,500	11,000	306,900	35,400	3,721,900	-	-	-	1,317,500	80,838,200
Interest cost	5,585,400	25,099,500	98,000	245,600	667,700	932,200	212,000	4,800	-	246,600	33,091,800
Expected return on plan assets	(10,137,100)	(44,661,300)	(257,600)	(537,500)	(1,432,500)	(1,417,100)	(511,800)	(10,300)	-	(442,100)	(59,407,300)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	-	-	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	1,494,200	7,988,200	32,200	59,500	1,100	328,700	81,200	2,900	-	64,600	10,052,600
Net periodic benefit cost	15,256,500	45,557,900	(116,400)	74,500	(728,300)	3,565,700	(218,600)	(2,600)	-	1,186,600	64,575,300
Headcounts for expense[1]											
EI RPP - DB service cost provision	662	2,270	1	8	2	175	-	-	-	46	3,164

[1] Note the 2017 expense is based on headcount as at December 31, 2015 post Tundra divestiture. Amounts summarized do not reflect the headcount adjustment.

	Enbridge Inc.	Enbridge Employee Services Canada 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
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	5,216,700	(9,181,400)	144,600	76,700	251,800	325,700	159,100	(900)	-	914,600	(2,093,100)
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)	(1,494,200)	(7,988,200)	(32,200)	(59,500)	(1,100)	(328,700)	(81,200)	(2,900)	-	(64,600)	(10,052,600)
Total recognized in other comprehensive loss (income)	3,722,500	(17,169,600)	112,400	17,200	250,700	(3,000)	77,900	(3,800)	-	850,000	(12,145,700)
Total recognized in net periodic benefit and other comprehensive loss (income)	18,979,000	28,388,300	(4,000)	91,700	(477,600)	3,562,700	(140,700)	(6,400)	-	2,036,600	52,429,600
Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year											
Initial net asset (obligation)	-	-	-	-	-	-	-	-	-	-	-
Prior service credit (cost)	-	-	-	-	-	-	-	-	-	-	-
Net gain (loss)	(1,437,800)	(6,274,100)	(32,200)	(52,300)	(10,500)	(285,000)	(73,400)	(2,400)	-	(88,400)	(8,256,100)
H. Weighted-average assumptions to determine benefit obligations											
Discount rate	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%	3.64%
Rate of compensation increase	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%	3.32%
Measurement date	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017
I. Assumptions to determine net cost											
Effective discount rate for benefit obligations	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	4.05%	Not applicable	4.05%	4.05%
Effective rate for interest on benefit obligations	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	Not applicable	3.60%	3.60%
Effective rate for service cost	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	4.15%	Not applicable	4.15%	4.15%
Effective rate for interest on service cost	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	Not applicable	3.85%	3.85%
Expected return on assets	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	Not applicable	7.00%	7.00%
Rate of compensation increase	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	3.94%	Not applicable	3.94%	3.94%
Headcount adjustment	93.77%	93.77%	93.77%	93.77%	93.77%	93.77%	93.77%	93.77%	Not applicable	93.77%	93.77%

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2017
Final US GAAP - January 15, 2018
Enbridge Inc. Pension Plans - EI SPP

	Enbridge Inc.	Enbridge Employee Services Canada 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)	(14,500)	-	-	-	-	-	-	-	-	-	(14,500)
Net gain (loss)	(45,258,300)	(12,234,200)	(291,200)	(230,200)	(401,800)	72,800	(5,814,600)	(99,800)	(14,700)	(1,583,400)	(65,855,400)
Accumulated other comprehensive income (loss)	(45,272,800)	(12,234,200)	(291,200)	(230,200)	(401,800)	72,800	(5,814,600)	(99,800)	(14,700)	(1,583,400)	(65,869,900)
Accumulated contributions in excess of net periodic benefit cost	18,468,800	(2,360,800)	(685,300)	4,080,700	(348,500)	(5,600)	2,570,400	431,400	(23,700)	(664,400)	21,463,000
Net asset (obligation) recognized in statement of financial position	(26,804,000)	(14,595,000)	(976,500)	3,850,500	(750,300)	67,200	(3,244,200)	331,600	(38,400)	(2,247,800)	(44,406,900)
F. Components of net periodic benefit cost											
Service cost	5,671,500	4,935,600	-	297,700	-	77,100	1,444,100	14,800	16,200	327,200	12,784,200
Interest cost	5,078,400	2,495,400	43,100	223,600	33,800	21,600	695,900	1,500	1,900	82,100	8,677,300
Expected return on plan assets	(6,468,600)	(2,562,000)	(47,900)	(480,200)	(5,500)	(25,700)	(946,800)	(18,400)	(900)	(72,400)	(10,628,400)
Amortization of initial net obligation (asset)	-	-	-	-	-	-	-	-	-	-	-
Amortization of prior service cost	1,800	-	-	-	-	-	-	-	-	-	1,800
Amortization of net (gain) loss	2,443,200	1,174,400	32,800	47,700	22,300	11,800	316,200	6,600	1,600	51,000	4,107,600
Net periodic benefit cost	6,726,300	6,043,400	28,000	88,800	50,600	84,800	1,509,400	4,500	18,800	387,900	14,942,500
Headcounts for expense[1]											
EI SPP (Only Senior Management Employees)	92	90	-	7	1	1	38	1	1	7	238

[1] Note the 2017 expense is based on headcount as at December 31, 2015 post Tundra divesture. Amounts summarized do not reflect the headcount adjustment.

	Enbridge Inc.	Enbridge Employee Services Canada 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
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	(106,800)	(9,570,700)	(317,700)	(654,800)	(11,700)	(291,100)	(57,100)	(22,000)	(15,500)	635,800	(10,411,600)
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)	(2,443,200)	(1,174,400)	(32,800)	(47,700)	(22,300)	(11,800)	(316,200)	(6,600)	(1,600)	(51,000)	(4,107,600)
Total recognized in other comprehensive loss (income)	(2,551,800)	(10,745,100)	(350,500)	(702,500)	(34,000)	(302,900)	(373,300)	(28,600)	(17,100)	584,800	(14,521,000)
Total recognized in net periodic benefit and other comprehensive loss (income)	4,174,500	(4,701,700)	(322,500)	(613,700)	16,600	(218,100)	1,136,100	(24,100)	1,700	972,700	421,500
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)	(2,017,800)	(545,500)	(13,000)	(10,300)	(17,800)	3,200	(259,200)	(4,400)	(700)	(70,600)	(2,936,100)
H. Weighted-average assumptions to determine benefit obligations											
Discount rate	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%	3.59%
Rate of compensation increase	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%	2.98%
Measurement date	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017	31-Dec-2017
I. Assumptions to determine net cost											
Effective discount rate for benefit obligations	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%
Effective rate for interest on benefit obligations	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%
Effective rate for service cost	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%	4.12%
Effective rate for interest on service cost	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%	3.91%
Expected return on assets	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%
Rate of compensation increase	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
Headcount adjustment	90.50%	90.50%	90.50%	90.50%	90.50%	90.50%	90.50%	90.50%	90.50%	90.50%	90.50%

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2017
Final US GAAP - January 15, 2018
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	297,466,300	5,790,200	2,827,900	306,084,400
Amounts recognized as a component of net periodic benefit cost				
Amortization	(14,661,800)	(285,400)	(139,400)	(15,086,600)
Effect of settlement	-	-	-	-
Total amount recognized as a component of net periodic benefit cost	(14,661,800)	(285,400)	(139,400)	(15,086,600)
Changes in plan assets and benefit obligations recognized in other comprehensive income				
Liability experience	42,355,900	848,300	814,900	44,019,100
Asset experience	(42,846,900)	(688,900)	(443,300)	(43,979,100)
Effect of curtailment	-	-	-	-
Extraordinary event that adjusts assets	-	-	-	-
Total amount recognized as a change in plan assets and benefit obligations	(491,000)	159,400	371,600	40,000
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	282,313,500	5,664,200	3,060,100	291,037,800
Q. DC Current service cost	652,700	41,000	35,800	729,500
Projected DC current service cost for fiscal year ending: 31-Dec-2018 :	99,700	-	-	99,700

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2017
US GAAP - January 2018
Enbridge Gas Distribution Non-Pension Post Retirement Benefit Plan

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Components of net periodic benefit cost				
Service cost	1,361,000	43,000	60,000	1,464,000
Interest cost	3,617,000	73,000	47,000	3,737,000
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	5,081,000	118,000	108,000	5,307,000
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	1,726,000	86,000	113,000	1,925,000
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)	1,623,000	84,000	112,000	1,819,000
Total recognized in net periodic benefit and other comprehensive loss (income) (income)	6,704,000	202,000	220,000	7,126,000
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)	(30,000)	(1,000)	-	(31,000)
Weighted-average assumptions to determine benefit obligations				
Effective discount rate for benefit obligations	3.58%	3.58%	3.58%	3.58%
Rate of compensation increase	3.22%	3.22%	3.22%	3.22%
Measurement date	31-Dec-17	31-Dec-17	31-Dec-17	31-Dec-17
Additional information for post-retirement medical plans				
Assumed health care trend rate				
a. Immediate Trend Rate	5.49%	5.71%	6.09%	5.50%
b. Ultimate Trend Rate	4.34%	4.47%	4.48%	4.34%
c. Year that the rate reaches ultimate trend rate	2034	2034	2034	2034
Assumed Drug trend rate				
a. Immediate Trend Rate	6.37%	6.60%	6.61%	6.37%
b. Ultimate Trend Rate	4.26%	4.49%	4.50%	4.27%
c. Year that the rate reaches ultimate trend rate	2034	2034	2034	2034
Assumed Other Medical and Dental trend rate				
a. Immediate Trend Rate	4.50%	4.50%	4.50%	4.50%
b. Ultimate Trend Rate	4.50%	4.50%	4.50%	4.50%
c. Year that the rate reaches ultimate trend rate	Not applicable	Not applicable	Not applicable	Not applicable
Assumptions to determine net cost				
Effective discount rate for benefit obligation	3.94%	3.94%	3.94%	3.94%
Effective rate for net interest cost	3.39%	3.39%	3.39%	3.39%
Effective rate for service cost	4.14%	4.14%	4.14%	4.14%
Effective rate for interest on service cost	3.95%	3.95%	3.95%	3.95%
Expected return on assets	Not applicable	Not applicable	Not applicable	Not applicable
Rate of compensation increase	3.47%	3.47%	3.47%	3.47%

Additional information for post-retirement medical plans

GAS DISTRIBUTION ACCESS RULE IMPACT DEFERRAL ACCOUNT

1. Within the EB-2016-0215 Final Accounting Order, included as Schedule 5 to the Decision and Rate Order, the Board approved the 2017 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 requirements in 2017 that caused incremental costs that Enbridge seeks to recover, the Company has included for recovery within the 2017 GDARIDA, the 2017 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.

Witnesses: D. McIlwraith
R. Small

4. Consistent with what was indicated within EB-2014-0195, as part of each of Enbridge's 2014 through 2016 Earnings Sharing Mechanism and Deferral Account Clearance proceedings, EB-2015-0122, EB-2016-0142, and EB-2017-0102, the Company requested and received approval to recover the 2014 through 2016 revenue requirements resulting from the LICSR changes.

5. As mentioned above, within this proceeding the Company has included for recovery within the 2017 GDARIDA, the 2017 revenue requirement, determined through a cost of service type calculation, which results from the LICSR changes. The Company is proposing to recover from ratepayers $0.266 million as part of the requested one time rate rider adjustment in January 2019, 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 2017 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 2017 actual required capital structure within the 2017 revenue requirement calculation. The approved 2013, 2014, 2015 and 2016 revenue requirement amounts credited to and recovered from ratepayers as part of the EB-2014-0195, EB-2015-0122, EB-2016-0142, and EB-2017-0102 proceedings, are also shown for continuity.

UTILITY CAPITAL STRUCTURE
2017 GDARIDA IMPACTS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
		2013 Actual Capital Structure			2014 Actual Capital Structure			2015 Actual Capital Structure			2016 Actual Capital Structure			2017 Actual Capital Structure		
Line No.		Component	Indicated Cost Rate	Return Component	Component	Indicated Cost Rate	Return Component	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	58.77	4.95	2.91	56.88	4.86	2.76
2.	Short-term debt	5.51	1.11	0.06	4.32	1.38	0.06	3.25	1.32	0.04	3.54	1.33	0.05	5.57	1.05	0.06
3.		61.67		3.34	61.87		3.17	62.03		3.07	62.31		2.96	62.45		2.82
4.	Preference shares	2.33	2.40	0.06	2.13	2.40	0.05	1.97	2.24	0.04	1.69	2.16	0.04	1.55	2.32	0.04
5.	Common equity	36.00	8.93	3.21	36.00	9.36	3.37	36.00	9.30	3.35	36.00	9.19	3.31	36.00	8.78	3.16
6.	Required Return on Rate Base	100.00		6.61	100.00		6.59	100.00		6.46	100.00		6.30	100.00		6.02

	($000's)	2013	2014	2015	2016	2017
7.	Ontario Utility Income	70.9	(63.7)	(181.5)	(183.1)	(184.7)
8.	Rate base	238.4	736.0	550.0	364.0	178.0
9.	Indicated rate of return	29.74 %	(8.65)%	(33.00)%	(50.30)%	(103.76)%
10.	(Def.) / suff. in rate of return	23.13 %	(15.24)%	(39.46)%	(56.60)%	(109.78)%
11.	Net (def.) / suff.	55.1	(112.2)	(217.0)	(206.0)	(195.4)
12.	Gross (def.) / suff.	75.0	(152.7)	(295.2)	(280.3)	(265.9)

UTILITY RATE BASE
2017 GDARIDA IMPACTS

Line No.	($000's)	2013	2014	2015	2016	2017
	Property, plant, and equipment					
1.	Cost or redetermined value	260.1	876.3	876.3	876.3	876.3
2.	Accumulated depreciation	(21.7)	(140.3)	(326.3)	(512.3)	(698.3)
3.		238.4	736.0	550.0	364.0	178.0
	Allowance for working capital					
4.	Accounts receivable merchandise finance plan	-	-	-	-	-
5.	Accounts receivable rebillable projects	-	-	-	-	-
6.	Materials and supplies	-	-	-	-	-
7.	Mortgages receivable	-	-	-	-	-
8.	Customer security deposits	-	-	-	-	-
9.	Prepaid expenses	-	-	-	-	-
10.	Gas in storage	-	-	-	-	-
11.	Working cash allowance	-	-	-	-	-
12.		-	-	-	-	-
13.	Ontario utility rate base	238.4	736.0	550.0	364.0	178.0

UTILITY INCOME
2017 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016	2017
	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	186.0	186.0
10.	Municipal and other taxes	-	-	-	-	-
11.	Total costs and expenses	47.3	186.0	186.0	186.0	186.0
12.	**Utility income before inc. taxes**	(47.3)	(186.0)	(186.0)	(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)	(2.9)	(1.3)
15.	Total income taxes	(118.2)	(122.3)	(4.5)	(2.9)	(1.3)
16.	**Ontario utility net income**	70.9	(63.7)	(181.5)	(183.1)	(184.7)

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016	2017
1.	Utility income before income taxes	(47.3)	(186.0)	(186.0)	(186.0)	(186.0)
	Add Backs					
2.	Depreciation and amortization	47.3	186.0	186.0	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	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	364.0	178.0
27.	Return component of debt	3.34%	3.17%	3.07%	2.96%	2.82%
28.	Interest expense	8.0	23.3	16.9	10.8	5.0
29.	Combined tax rate	26.500%	26.500%	26.500%	26.500%	26.500%
30.	Income tax credit	(2.1)	(6.2)	(4.5)	(2.9)	(1.3)
31.	**Total income taxes**	(118.2)	(122.3)	(4.5)	(2.9)	(1.3)

UTILITY REVENUE REQUIREMENT
2017 GDARIDA IMPACTS

($000's)

Line No.		2013	2014	2015	2016	2017
	Cost of capital					
1.	Rate base	238.4	736.0	550.0	364.0	178.0
2.	Required rate of return	6.61%	6.59%	6.46%	6.30%	6.02%
3.	Cost of capital	15.8	48.5	35.5	22.9	10.7
	Cost of service					
4.	Gas costs	-	-	-	-	-
5.	Operation and Maintenance	-	-	-	-	-
6.	Depreciation and amortization	47.3	186.0	186.0	186.0	186.0
7.	Municipal and other taxes	-	-	-	-	-
8.	Cost of service	47.3	186.0	186.0	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)	(2.9)	(1.3)
14.	Income taxes on earnings	(118.2)	(122.3)	(4.5)	(2.9)	(1.3)
	Taxes on (def) / suff.					
15.	Gross (def.) / suff.	75.0	(152.7)	(295.2)	(280.3)	(265.9)
16.	Net (def.) / suff.	55.1	(112.2)	(217.0)	(206.0)	(195.4)
17.	Taxes on (def.) / suff.	(19.9)	40.5	78.2	74.3	70.5
18.	**Revenue requirement**	(75.0)	152.7	295.2	280.3	265.9
	Revenue at existing Rates					
19.	Gas sales	0.0	0.0	0.0	0.0	0.0
20.	Transportation service	0.0	0.0	0.0	0.0	0.0
21.	Transmission, compression and storage	0.0	0.0	0.0	0.0	0.0
22.	Rounding adjustment	0.0	0.0	0.0	0.0	0.0
23.	Revenue at existing rates	0.0	0.0	0.0	0.0	0.0
24.	**Gross revenue (def.) / suff.**	75.0	(152.7)	(295.2)	(280.3)	(265.9)

2017 DEFERRED REBATE ACCOUNT
REQUESTED FOR CLEARANCE JANUARY 1, 2019

1. The 2017 Deferred Rebate Account ("DRA") was approved by the Board within the EB-2016-0215 Accounting Order, at page 15. The description and scope of the 2017 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. In October and November 2017, the Company cleared 2016 deferral and variance accounts which were approved within the EB-2017-0102 proceeding. The $1.8 million recorded in the 2017 DRA and requested for clearance (and corresponding interest of $57.0 thousand), reflects the outstanding amount resulting from the clearance of deferral and variance accounts which occurred during 2017, and the inability to locate all the intended customers.

2018 TRANSITION IMPACT OF ACCOUNTING CHANGES DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE JANUARY 1, 2019

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 five installments (for each of 2013 through 2017) of $4.436 million each (1/20 of $88.716 million), were approved for recovery within the EB-2013-0046, EB-2014-0195, EB-2015-0122, EB-2016-0142 and EB-2017-0102 proceedings.

3. Enbridge is now requesting recovery of the sixth, or 2018 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: R. Small
C. Tuckwell

2013, 2014, 2015, 2016, AND 2017 CUSTOMER CARE CIS RATE SMOOTHING DEFERRAL ACCOUNTS
REQUESTED FOR CLEARANCE JANUARY 1, 2019

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.

Witnesses: D. McIlwraith
R. Small

4. Within the EB-2011-0354 Final Rate Order, EB-2012-0459 Final Accounting Order, EB-2014-0276 Final Accounting Order, EB-2015-0114 Decision and Accounting Order, and EB-2016-0215 Decision and Rate Order, the Board approved of the 2013, 2014, 2015, 2016, and 2017 CCCISRSDAs. The principal balance recorded within each of the 2013, 2014, 2015, 2016, and 2017 accounts ($4.6 million, $2.9 million, $1.1 million, credit of $0.8 million, and credit of $2.8 million), reflects each year's approved variance between the forecast customer care and CIS costs and the smoothed 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 net principal balance at this time, as the net balance will be offset by amounts to be recorded within the 2018 CCCISRSDA, and the 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, 2015, 2016, and 2017 CCCISRSDAs, in the amounts of $85.3 thousand, $53.9 thousand, $20.8 thousand,($14.6) thousand, and ($59.6) 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.

2017 ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE JANUARY 1, 2019

1. The 2017 Electric Program Earnings Sharing Deferral Account (“EPESDA”) was approved by the Board within the EB-2016-0215 Decision and Rate Order, as part of the Final Accounting Order, included as Schedule 5 to the Decision. The description and scope of the 2017 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 is 50% of net revenues, using fully allocated costs, as was determined in the DSM guidelines proceeding EB-2008-0346.

2. On June 10, 2016, the Minister of Energy provided a direction to the IESO whereby, the IESO shall, in consultation with the Distributors, centrally design, fund and deliver “a province-wide home Conservation and Demand Management (CDM) pilot program for residential consumers.” The IESO Whole Home Pilot was launched on May 29, 2017 and leverages the existing Enbridge Gas DSM Home Energy Conservation (HEC) program by adding an electric assessment component, and offering prescriptive electric incentives to participants. The aim of this “one stop shop” approach is to increase Enbridge Gas Distribution participant satisfaction, provide additional energy literacy to Ontario residents, and remove the barriers around access to incentives from different parties.

3. The ($0.7) million recorded in the 2017 EPESDA and requested for clearance, reflects the ratepayers 50% share of the net recovery generated by providing Conservation & Demand Management (“CDM”) activities, using fully allocated costs, as determined in the DSM guidelines proceeding EB-2008-0346.

Witness: J. Tideman

2017 ONTARIO ENERGY BOARD COST ASSESSMENT VARIANCE ACCOUNT
REQUESTED FOR CLEARANCE JANUARY 1, 2019

1. The purpose of the 2017 Ontario Energy Board Cost Assessment Variance Account ("OEBCAVA") was to record any material variances between the Board costs assessed to Enbridge through application of the revised Cost Assessment Model (CAM), which became effective April 1, 2016, and the Board costs which were included in rates during the Custom IR term, which were determined through application of the prior Cost Assessment Model. The 2017 OEBCAVA was approved as part of the EB-2016-0215 Final Accounting Order, included as Schedule 5 to the Decision and Rate Order, dated December 8, 2016. The scope of the account is consistent with 2016 OEBCAVA which was originally approved for establishment by Board letter dated February 9, 2016, entitled: *Revisions to the Ontario Energy Board Cost Assessment Model.*

2. The amount recorded within the 2017 OEBCAVA is $2,649.9 thousand. This amount reflects the variance between OEB costs assessed to Enbridge in each quarter of fiscal 2017, utilizing the revised CAM, and Enbridge's average quarterly OEB cost assessment under the prior CAM. For purposes of calculating amounts to be recovered through the 2017 OEBCAVA, the Company used the Board's fiscal 2015 / 2016 cost assessment amount of $2.8 million (or an average of $0.7 million per quarter) as the comparator, as it was the most recent amount which the Company was expected to accommodate through its Custom Incentive Regulation established rates. Table 1 below, shows the calculation of the amount recorded in the 2017 OEBCAVA, while Table 2 shows the calculation of the average 2015 / 2016 Board costs assessed to the Company under the prior CAM.

Witness: R. Small

3. Within this proceeding, the Company is requesting clearance of the principal and interest balances recorded in the 2017 OEBCAVA, in the amount of $2,649.9 thousand and $64.6 thousand respectively, as shown in Exhibit C, Tab 1, Schedule 1, page 3.

Table 1

OEB assessment	Fiscal 2017 OEB cost assessment amounts under the revised CAM	Average cost assessment based on previous CAM*	Variance recorded in the 2017 OEBCAVA
	($)	($)	($)
Q4 2016/17 - Jan. 1, 2017	1,342,573	699,846	642,727
Q1 2017/18 - Apr. 1, 2017	1,393,342	699,846	693,496
Q2 2017/18 - July 1, 2017	1,393,343	699,846	693,497
Q3 2017/18 - Oct. 1, 2017	1,319,997	699,846	620,151
Total	5,449,255	2,799,383	2,649,872

* Enbridge utilized the average of the OEB's fiscal 2015/2016 quarterly invoiced amounts, determined under the previous CAM, as representative of the OEB costs embedded in 2017 rates.

Table 2

OEB Cost Assessment Based on prior CAM	Qtr. #	Quarterly Assessment	Total for the year	Average/Qtr
		$	$	$
OEB Fiscal 2015/2016	1	656,800		
	2	656,800		
	3	655,137		
	4	830,646	2,799,383	699,846

Witness: R. Small

2018 CONSTANT DOLLAR NET SALVAGE ADJUSTMENT DEFERRAL ACCOUNT
REQUESTED FOR CLEARANCE JANUARY 1, 2019

1. In accordance with the EB-2012-0459 decision (Enbridge Gas Distribution's 2014 – 2018 Custom Incentive Rate Application), the purpose of the CDNSADA was to record and clear the credit to ratepayers that resulted from the adoption of the Constant Dollar Net Salvage ("CDNS") approach for determining the net salvage percentages to be included within Enbridge's depreciation rates.

2. As a result of the adoption of the CDNS approach, the Company had an estimated excess net salvage reserve when compared to the reserve which accumulated while the Company employed the Traditional Method for determining net salvage percentages. The net salvage reserve is recorded within a liability account which, for utility rate base determination purposes, is accounted for as an offset against specific property, plant and equipment asset category balances as part of accumulated depreciation. Within the EB-2012-0459 decision, the Board ordered the refund to ratepayers of $379.8 million in net salvage reserve over the 2014 – 2018 period, through rate rider D. The annual refund amounts were: 2014 - $96.8 million, 2015 - $90.4 million, 2016 - $83.9 million, 2017 - $77.5 million, and 2018 - $31.1 million.

3. On a monthly basis each year, the net salvage liability (or accumulated depreciation for utility rate base purposes) was to be debited by the forecast monthly rider amount, with a corresponding credit recorded in the CDNSADA. Within the same month, the CDNSADA was to be debited, with a corresponding credit to accounts receivable, for the actual amount refunded to customers through rate rider D.

4. In each year, the final balance in the account was to be the cumulative variance between the amounts proposed for clearance and the actual amounts cleared. The balance was to be transferred to the following year's CDNSADA, and at the end of 2018, any residual balance was to be cleared in a post 2018 true up, ensuring the actual amount cleared was equivalent to the required $379.8 million. No interest was to be calculated on the CDNSADA balance.

5. In Enbridge's 2018 Rate Adjustment Application (EB-2017-0086), the Company applied to discontinue rate rider D, because it was expected that Enbridge would have returned more than the required $379.8 million by the end of 2017. The Board-approved EB-2017-0086 (2018 Rate Adjustment application) Amended Settlement Proposal indicated that rate rider D will be discontinued in 2018, and the 2018 CDNSADA is to be utilized to effect a final true up of all site restoration cost completion implications.

6. As a result, it was agreed and approved that the 2018 CDNSADA is to work as follows:
    a. The final balance in the 2017 CDNSADA will be transferred to the 2018 CDNSADA account.

    b. On a monthly basis during 2018, the net salvage liability (or accumulated depreciation for utility rate base purposes) will be debited by the EB-2012-0459 2018 approved forecast monthly rider amount (totaling $31.1M), with a corresponding credit recorded in the CDNSADA.

c. With the discontinuance of Rider D in 2018, there will be no monthly debit to the CDNSADA, with corresponding credit to accounts receivable, for the actual amounts refunded to customers through Rate Rider D.

d. The impact of this will be to reduce the actual cumulative variance/over refund (or debit/receivable) experienced through 2017, as compared to the approved forecast refund through 2017 of $348.7 million, to a net variance versus the total Board ordered refund of $379.8 million, that was to be refunded through 2018.

e. A forecast debit/receivable balance (reflecting the forecast net Rider D over refund) will be sought for clearance as part of the 2017 ESM and Deferral Clearance application. Subject to clearance occurring during 2018, the 2018 CDNSADA balance at the end of 2018 will be $0.

7. In accordance with the EB-2017-0086 approved Amended Settlement Proposal, the Company is requesting the recovery of $6,468 thousand through the 2018 CDNSADA as part of this proceeding, in order to effect a final true up of all site restoration cost completion implications.

8. As seen in Attachment 1 to this exhibit, the Company refunded ratepayers a total of $386,268 thousand (Column 15, Row 10) as a result of rate Rider Ds which were in place between 2014 and 2017, or $37,612 thousand (Column 15, Row 16) more than the EB-2012-0459 approved forecast amount of $348,656 thousand (Column 15, Row 4) which was to be refunded over that time period. Taking account of the 2018 drawdown of the net salvage liability (debiting the net salvage liability and crediting the CDNSADA), by the EB-2012-0459 approved 2018 refund

amount of $31,144 thousand (Column 14, Row 5), results in the net Rider D over refund, or debit/receivable balance, of $6,468 thousand (Column 15, Row 17) requested for recovery in the 2018 CDNSADA (actual refunds of $386,268 thousand, less the approved refund of $379,800 thousand).

9. The recovery of $6,468 thousand will result in a 2018 CDNSADA balance of $0 at the end of 2018.

10. The proposed clearance methodology for the 2018 CDNSADA is described at Exhibit C. Tab 2, Schedule 1.

Witnesses: A. Kacicnik
R. Small

SITE RESTORATION COST RIDER - ACTUAL VS FORECAST - 2014 TO 2018

('$ 000)		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
ITEM NO	Year	Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 300 Int	Total	Cumulative Total
	Approved Forecast Credit															
1.	2014 (Oct - Dec)	$ 70,667	$ 23,341	$ 1	$ 0	$ 946	$ 411	$ 969	$ 8	$ 189	$ 162	$ 116	$ 6	$ 31	$ 96,849	$ 96,849
2.	2015	$ 65,699	$ 22,164	$ 1	$ 0	$ 685	$ 411	$ 952	$ 8	$ 142	$ 158	$ 139	$ 6	$ 28	$ 90,392	$ 187,241
3.	2016	$ 59,974	$ 20,973	$ 1	$ 0	$ 982	$ 557	$ 1,087	$ 7	$ 73	$ 91	$ 156	$ 6	$ 28	$ 83,936	$ 271,177
4.	2017	$ 55,388	$ 19,327	$ 1	$ 0	$ 1,021	$ 478	$ 964	$ 7	$ 61	$ 61	$ 142	$ 5	$ 25	$ 77,479	$ 348,656
5.	2018	$ 22,266	$ 7,890	$ -	$ 0	$ 366	$ 151	$ 368	$ 3	$ 19	$ 22	$ 57	$ 2	$ -	$ 31,144	$ 379,800
6.	**2014 to 2018 Approved Rider D Credit**	**$ 273,994**	**$ 93,695**	**$ 4**	**$ 0**	**$ 4,000**	**$ 2,008**	**$ 4,341**	**$ 33**	**$ 484**	**$ 494**	**$ 610**	**$ 25**	**$ 111**	**$ 379,800**	
	Actual Credit															
7.	2014 (Oct - Dec)	$ 98,729	$ 32,650	$ 1	$ 19	$ 891	$ 480	$ 969	$ 8	$ 127	$ 159	$ 149	$ 6	$ 45	$ 134,233	$ 134,233
8.	2015	$ 69,131	$ 23,553	$ 1	$ 17	$ 978	$ 416	$ 952	$ 9	$ 78	$ 134	$ 145	$ 6	$ 25	$ 95,444	$ 229,678
9.	2016	$ 56,963	$ 20,088	$ 0	$ 15	$ 1,160	$ 528	$ 1,087	$ 8	$ 40	$ 85	$ 155	$ 6	$ 17	$ 80,154	$ 309,832
10.	2017	$ 54,641	$ 19,161	$ 0	$ 5	$ 951	$ 498	$ 915	$ 8	$ 45	$ 65	$ 144	$ 5	$ -	$ 76,437	$ 386,268
11.	2018	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 386,268
12.	**2014 to 2018 Actual Rider D Credit**	**$ 279,463**	**$ 95,452**	**$ 2**	**$ 55**	**$ 3,980**	**$ 1,922**	**$ 3,924**	**$ 34**	**$ 290**	**$ 443**	**$ 593**	**$ 23**	**$ 87**	**$ 386,268**	
	Variance															
13.	2014 (Oct - Dec)	$ 28,061	$ 9,309	$ (0)	$ 19	$ (55)	$ 68	$ 0	$ 1	$ (62)	$ (3)	$ 32	$ 0	$ 14	$ 37,384	$ 37,384
14.	2015	$ 3,432	$ 1,389	$ (0)	$ 17	$ 293	$ 5	$ (0)	$ 2	$ (64)	$ (24)	$ 6	$ (0)	$ (3)	$ 5,052	$ 42,436
15.	2016	$ (3,011)	$ (885)	$ (1)	$ 15	$ 178	$ (29)	$ (0)	$ 1	$ (33)	$ (6)	$ (1)	$ 0	$ (11)	$ (3,782)	$ 38,654
16.	2017	$ (747)	$ (166)	$ (1)	$ 5	$ (69)	$ 20	$ (49)	$ 1	$ (16)	$ 3	$ 3	$ (0)	$ (25)	$ (1,042)	$ 37,612
17.	2018	$ (22,266)	$ (7,890)	$ -	$ (0)	$ (366)	$ (151)	$ (368)	$ (3)	$ (19)	$ (22)	$ (57)	$ (2)	$ -	$ (31,144)	$ 6,468
18.	**2014 to 2018 Rider D Variance**	**$ 5,469**	**$ 1,758**	**$ (2)**	**$ 55**	**$ (19)**	**$ (86)**	**$ (417)**	**$ 1**	**$ (194)**	**$ (51)**	**$ (17)**	**$ (2)**	**$ (25)**	**$ 6,468**	

2017 DAWN ACCESS COSTS DEFERRAL ACCOUNT

1. The purpose of the 2017 DACDA, as established in the EB-2014-0323 Dawn Access Settlement Agreement, was to record for recovery the revenue requirement impact of the incremental costs incurred to implement the Dawn Transportation Service (“DTS”), including the costs for required system changes. In addition, in accordance with the 2017 Rate Application Settlement Proposal, EB-2016-0215, the revenue requirement related to additional costs incurred to accommodate the heat value conversion modification, implemented in conjunction with the DTS system development process, was also to be recorded within this account. Under the terms of the EB-2014-0323 Settlement Agreement, recovery of amounts recorded in the DACDA will be from all bundled customers, regardless of whether they are system or direct purchase and regardless of the service to which they currently subscribe, because all have the option of taking DTS if they so choose. Further details explaining the DACDA, including the recovery method, are included within Section 2.7 of the Settlement Agreement filed at Exhibit B, Tab 2, Schedule 1 of the EB-2014-0323 proceeding.

2. All incremental costs incurred by the Company to implement the DTS (and functionality for 2 additional receipt points) and heat value conversion modification were capital in nature. Capital costs of $6.5 million were incurred to develop, test, and integrate enhancements to the functionality of Enbridge’s EnTRAC and connected systems. The systems modifications were placed into service effective November 1, 2017, in conjunction with the implementation of Phase 2 of the Dawn Access Settlement. The associated revenue requirement calculation sought for refund/recovery in association with those capital costs, includes the typical items in a cost of service revenue requirement, such as total return on rate base, including interest and return on equity, depreciation, and income taxes. The Company has

used the 2017 actual required capital structure within the revenue requirement calculation.

3. Within this proceeding, the Company is proposing to credit to ratepayers $0.9 million as part of the requested one time bill adjustment in January 2019, as shown in the proposed clearance balances at Exhibit C, Tab 1, Schedule 1, page 3, Columns 3 and 4. This amount represents the 2017 revenue requirement associated with the $6.5 million capital spending incurred to accommodate the DTS and heat value changes. There will also be revenue requirement amounts to be recorded in relation to this spending within future DACDAs. Those future amounts will be higher, as the 2017 amount reflects only a partial year of in-service effectivity, and benefits from a significant Capital Cost Allowance ("CCA") tax deduction that does not repeat in subsequent years beyond 2018.

4. The determination of the 2017 DACDA revenue requirement deferral account amount and related costs is shown in pages 3 through 7 of this schedule.

UTILITY CAPITAL STRUCTURE
2017 DACDA IMPACTS

		Col. 1	Col. 2	Col. 3
		2017 Actual Capital Structure		
Line No.		Component	Indicated Cost Rate	Return Component
		%	%	%
1.	Long-term debt	56.88	4.86	2.76
2.	Short-term debt	5.57	1.05	0.06
3.		62.45		2.82
4.	Preference shares	1.55	2.32	0.04
5.	Common equity	36.00	8.78	3.16
6.		100.00		6.02

	($ 000's)	2017
7.	Ontario Utility Income	685.0
8.	Rate base	259.7
9.	Indicated rate of return	263.76 %
10.	(Def.) / suff. in rate of return	257.74 %
11.	Net (def.) / suff.	669.4
12.	Gross (def.) / suff.	910.7

UTILITY RATE BASE
2017 DACDA IMPACTS

($ 000's)

Line No.		2017
	Property, plant, and equipment	
1.	Cost or redetermined value	264.4
2.	Accumulated depreciation	(4.7)
3.		259.7
	Allowance for working capital	
4.	Accounts receivable merchandise finance plan	-
5.	Accounts receivable rebillable projects	-
6.	Materials and supplies	-
7.	Mortgages receivable	-
8.	Customer security deposits	-
9.	Prepaid expenses	-
10.	Gas in storage	-
11.	Working cash allowance	-
12.		-
13.	**Ontario utility rate base**	259.7

UTILITY INCOME
2017 DACDA IMPACTS

($ 000's)

Line No.		2017
	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	112.3
10.	Municipal and other taxes	-
11.	Total costs and expenses	112.3
12.	**Utility income before inc. taxes**	(112.3)
	Income taxes	
13.	Excluding interest shield	(795.4)
14.	Tax shield on interest expense	(1.9)
15.	Total income taxes	(797.3)
16.	**Ontario utility net income**	685.0

UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2017 DACDA IMPACTS

($ 000's)

Line No.		2017
1.	Utility income before income taxes	(112.3)
	Add Backs	
2.	Depreciation and amortization	112.3
3.	Large corporation tax	-
4.	Other non-deductible items	-
5.	Any other add back(s)	-
6.	Total added back	112.3
7.	Sub total - pre-tax income plus add backs	-
	Deductions	
8.	Capital cost allowance - Federal	3,001.6
9.	Capital cost allowance - Provincial	3,001.6
10.	Items capitalized for regulatory purposes	-
11.	Deduction for "grossed up" Part V1.1 tax	-
12.	Amortization of share and debt issue expense	-
13.	Amortization of cumulative eligible capital	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-
15.	Any other deduction(s)	-
16.	Total Deductions - Federal	3,001.6
17.	Total Deductions - Provincial	3,001.6
18.	Taxable income - Federal	(3,001.6)
19.	Taxable income - Provincial	(3,001.6)
20.	Income tax provision - Federal	(450.2)
21.	Income tax provision - Provincial	(345.2)
22.	Income tax provision - combined	(795.4)
23.	Part V1.1 tax	-
24.	Investment tax credit	-
25.	Total taxes excluding tax shield on interest expense	(795.4)
	Tax shield on interest expense	
26.	Rate base as adjusted	259.7
27.	Return component of debt	2.82%
28.	Interest expense	7.3
29.	Combined tax rate	26.500%
30.	Income tax credit	(1.9)
31.	**Total income taxes**	(797.3)

UTILITY REVENUE REQUIREMENT
2017 DACDA IMPACTS

($ 000's)

Line No.		2017
	Cost of capital	
1.	Rate base	259.7
2.	Required rate of return	6.02%
3.	Cost of capital	15.6
	Cost of service	
4.	Gas costs	-
5.	Operation and Maintenance	-
6.	Depreciation and amortization	112.3
7.	Municipal and other taxes	-
8.	Cost of service	112.3
	Misc. & Non-Op. Rev	
9.	Other operating revenue	-
10.	Other income	-
11.	Misc, & Non-operating Rev.	-
	Income taxes on earnings	
12.	Excluding tax shield	(795.4)
13.	Tax shield provided by interest expense	(1.9)
14.	Income taxes on earnings	(797.3)
	Taxes on (def) / suff.	
15.	Gross (def.) / suff.	910.7
16.	Net (def.) / suff.	669.4
17.	Taxes on (def.) / suff.	(241.3)
18.	**Revenue requirement**	(910.7)
	Revenue at existing Rates	
19.	Gas sales	0.0
20.	Transportation service	0.0
21.	Transmission, compression and storage	0.0
22.	Rounding adjustment	0.0
23.	Revenue at existing rates	0.0
24.	**Gross revenue (def.) / suff.**	910.7

CLEARANCE OF 2017 DEFERRAL AND VARIANCE ACCOUNT BALANCES

1. The Company is proposing to clear 2017 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 January 2019 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 2017 consumption volume for the period January 1, 2017 to December 31, 2017, and will be recovered or refunded as a one-time billing adjustment in the month of January 2019.

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 2017 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 2017 consumption volumes for each rate class and each type of service.

4. The table on page 6 displays the bill adjustment in January 2019 for typical customers resulting from the clearance of the 2017 Deferral and Variance Account balances. These bill adjustments will be shown as a separate line item on customers' 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 in previous years, the Company would like to highlight proposed clearance methodology for the following two accounts which will be cleared for the first time as part of this application: 1) Dawn Access Costs Deferral Account (DACDA), 2) Constant Dollar Net Salvage Adj. Deferral Account (CDNSADA).

DACDA:

6. The DACDA was established in the EB-2014-0323 Settlement Agreement and the purpose of the account is to record the revenue requirement impact of the incremental costs incurred to implement the Dawn Transportation Service (DTS), including the costs for required system changes.

7. In addition, in accordance with 2017 Rate Adjustment Settlement Proposal dated November 28, 2016 (EB-2016-0215), the revenue requirement related to additional costs incurred to accommodate the heat value conversion modification, being implemented in conjunction with the Dawn Transportation Service system development process will also be recorded within this account.

8. Under the terms of the EB-2014-0323 Settlement Agreement, Item 2.7 Recovery of Implementation Costs dated December 4, 2014, recovery of amounts recorded in the DCADA will be from all bundled customers.

> *2.7 Recovery of Implementation Costs*
>
> *"… All parties agree that Enbridge should recover the costs of implementing DTS from bundled customers because all bundled customers, regardless of whether they are system or direct purchase and regardless of the service to which they presently subscribe, have the option of taking DTS if they choose to do so".*

Witnesses: J. Collier
A. Kacicnik
B. So

CDNSADA

9. The Decision and Rate Order issued by the Board on December 7, 2017 in Enbridge's 2018 rate adjustment proceeding (EB-2017-0086) approved the Amended Settlement Proposal, dated December 6, 2017. The Amended Settlement Proposal included the agreement to discontinue Rider D, the Site Restoration Cost Clearance (SRC), in 2018, and clear the final balance in the CDNSADA as part of this 2017 ESM application (see Amended Settlement Proposal, Exhibit N2, Tab 1, Schedule 1, Adjustment 4, page 16). The final balance in the CDNSADA is approximately $6.5 million (see Exhibit A, Tab 2, Schedule 1, Appendix A).

10. The Amended Settlement Proposal from Enbridge's 2018 rate adjustment proceeding indicates that as part of this 2017 ESM proceeding, Enbridge will "include the methodology for the proposed disposition [of the CDNSADA] including true-up of any over-and under-refunds to customer classes". The parties to the Amended Settlement Proposal in the 2018 rate adjustment proceeding acknowledged and agreed that "any necessary determinations about the disposition of the CDNSADA will be made by the OEB hearing panel considering Enbridge's 2017 ESM proceeding."

11. Enbridge proposes to clear the final balance in the CDNSADA in the manner described in the 2018 rate adjustment proceeding. This was described in Table 6 attached to APPrO Interrogatory #2 (EB-2016-0086, Exhibit I.D2.EGDI.APPrO.2). This response laid out the cumulative (actual vs. forecast) variance of over-refunded and under-refunded SRC amounts for each rate class for the Custom IR 2014 – 2018 period. The net variance of Rider D over refund, or debit/receivable balance, of $6,468 as shown in EB-2018-0131, Exhibit C, Tab 1, Schedule 12, page 3 of 3,

Attachment #1 and the variance for each customer class are reproduced below for reference.

SITE RESTORATION COST RIDER - ACTUAL VS FORECAST VARIANCE - 2014 TO 2018

('$ 000)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
Year	Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 300 Int	Total	Cumulative Total
Variance															
2014	$ 28,061	$ 9,309	$ (0)	$ 19	$ (55)	$ 68	$ 0	$ 1	$ (62)	$ (3)	$ 32	$ 0	$ 14	$ 37,384	$ 37,384
2015	$ 3,432	$ 1,389	$ (0)	$ 17	$ 293	$ 5	$ (0)	$ 2	$ (64)	$ (24)	$ 6	$ (0)	$ (3)	$ 5,052	$ 42,436
2016	$ (3,011)	$ (885)	$ (1)	$ 15	$ 178	$ (29)	$ (0)	$ 1	$ (33)	$ (6)	$ (1)	$ 0	$ (11)	$ (3,782)	$ 38,654
2017	$ (747)	$ (166)	$ (1)	$ 5	$ (69)	$ 20	$ (49)	$ 1	$ (16)	$ 3	$ 3	$ (0)	$ (25)	$ (1,042)	$ 37,612
2018	$ (22,266)	$ (7,890)	$ -	$ (0)	$ (366)	$ (151)	$ (368)	$ (3)	$ (19)	$ (22)	$ (57)	$ (2)	$ -	$ (31,144)	$ 6,468
2014 to 2018 Rider D Variance	**$ 5,469**	**$ 1,758**	**$ (2)**	**$ 55**	**$ (19)**	**$ (86)**	**$ (417)**	**$ 1**	**$ (194)**	**$ (51)**	**$ (17)**	**$ (2)**	**$ (25)**	**$ 6,468**	

12. As described above, the over-refunded and under-refunded SRC amounts shown in the above table will be directly allocated to each rate class as part of the clearance of Enbridge's 2017 deferral and variance accounts.

Witnesses: J. Collier
A. Kacicnik
B. So

UNIT RATE AND TYPE OF SERVICE: CLEARING IN JANUARY 2019

		COL.1
		Unit Rate (¢/m³)
Bundled Services:		
RATE 1	- SYSTEM SALES	0.0591
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0468
	- DAWN T-SERVICE	0.0468
	- WESTERN T-SERVICE	0.0591
RATE 6	- SYSTEM SALES	0.0849
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0727
	- DAWN T-SERVICE	0.0727
	- WESTERN T-SERVICE	0.0849
RATE 9	- SYSTEM SALES	(9.1216)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.0000
	- DAWN T-SERVICE	0.0000
	- WESTERN T-SERVICE	0.0000
RATE 100	- SYSTEM SALES	(0.3771)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.3893)
	- DAWN T-SERVICE	0.0000
	- WESTERN T-SERVICE	(0.3771)
RATE 110	- SYSTEM SALES	0.0035
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0087)
	- DAWN T-SERVICE	(0.0087)
	- WESTERN T-SERVICE	0.0035
RATE 115	- SYSTEM SALES	(0.0431)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0383)
	- DAWN T-SERVICE	(0.0383)
	- WESTERN T-SERVICE	(0.0261)
RATE 135	- SYSTEM SALES	(0.0056)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0179)
	- DAWN T-SERVICE	(0.0179)
	- WESTERN T-SERVICE	(0.0056)
RATE 145	- SYSTEM SALES	(0.4138)
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.4260)
	- DAWN T-SERVICE	(0.4260)
	- WESTERN T-SERVICE	(0.4138)
RATE 170	- SYSTEM SALES	0.0076
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	(0.0047)
	- DAWN T-SERVICE	(0.0047)
	- WESTERN T-SERVICE	0.0076
RATE 200	- SYSTEM SALES	0.1336
	- BUY/SELL	0.0000
	- ONTARIO T-SERVICE	0.1213
	- DAWN T-SERVICE	0.0000
	- WESTERN T-SERVICE	0.1336
Unbundled Services:		
RATE 125	- All	(6.6210)
RATE 300	- All	(266.5374)
RATE 332	- All	(2.3824)

DETERMINATION OF BALANCES TO BE CLEARED
FROM THE 2017 DEFERRAL AND VARIANCE ACCOUNTS

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
1.	TRANSACTIONAL SERVICES D/A	1,206.4	20.8	1,227.2
2.	UNACCOUNTED FOR GAS V/A	(1,129.9)	(34.5)	(1,164.4)
3.	STORAGE AND TRANSPORTATION D/A	22,654.8	530.2	23,185.0
4.	DEFERRED REBATE ACCOUNT	1,834.0	57.0	1,891.0
5.	DEMAND SIDE MANAGEMENT 2015	-	-	-
6.	LOST REVENUE ADJ MECHANISM 2015	-	-	-
7.	DEMAND SIDE MANAGEMENT INCENTIVE 2015	-	-	-
8.	RATE 332 VARIANCE ACCOUNT	-	-	-
9.	CREDIT FINAL BILL D/A	-	-	-
10.	GTA INCREMNTL TRANSMISSIONAL CAPITAL RR D/A	-	-	-
11.	OEB COST ASSESSMENT VARIANCE ACCOUNT	2,649.9	64.6	2,714.5
12.	GAS DISTRIBUTION ACCESS RULE D/A 2016	265.9	-	265.9
13.	AVERAGE USE TRUE-UP V/A	(4,035.7)	(72.6)	(4,108.3)
14.	POST-RETIREMENT TRUE-UP V/A	(4,299.2)	(94.7)	(4,393.9)
15.	2017 CUSTOMER CARE CIS RATE SMOOTHING D/A		(59.6)	(59.6)
16.	2016 CUSTOMER CARE CIS RATE SMOOTHING D/A		(14.6)	(14.6)
17.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A		20.8	20.8
18.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A		53.9	53.9
19.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A		85.3	85.3
20.	GREEN HOUSE GAS EMISSIONS IMPACT D/A			-
21.	UNABSORBED DEMAND COST D/A	-	-	-
22.	ELECTRIC PROGRAM EARNINGS SHARING D/A	(680.2)	(12.4)	(692.6)
23.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8	-	4,435.8
24.	DAWN ACCESS COSTS D/A	(910.7)	-	(910.7)
25.	CONSTANT DOLLAR NET SALVAGE ADJ. D/A	6,468.3	-	6,468.3
26.	EARNINGS SHARING MECHANISM	(23,550.0)	(423.4)	(23,973.4)
	TOTAL	4,909.4	120.8	5,030.2

Classification and Allocation of Deferral and Variance Account Balances

ITEM NO.		COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)	COL. 11 BUNDLED ANNUAL DELIVERIES ($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	0.0
2.	TRANSACTIONAL SERVICES D/A	1,227.2	1,107.3			38.6	81.3					
3.	UNACCOUNTED FOR GAS V/A	(1,164.4)			(1,164.4)							
4.	STORAGE AND TRANSPORTATION D/A	23,185.0				7,464.4	15,720.6					
5.	DEFERRED REBATE ACCOUNT	1,891.0			1,891.0							
6.	DEMAND SIDE MANAGEMENT 2015	0.0							0.0			
7.	LOST REVENUE ADJ MECHANISM 2015	0.0							0.0			
8.	DEMAND SIDE MANAGEMENT INCENTIVE 2015	0.0							0.0			
9.	RATE 332 VARIANCE ACCOUNT	0.0			0.0					0.0		
10.	CREDIT FINAL BILL D/A	0.0							0.0			
11.	GTA INCREMNTL TRANSMISSIONAL CAPITAL RR D/A	0.0							0.0			
12.	OEB COST ASSESSMENT VARIANCE ACCOUNT	2,714.5									2,714.5	
13.	GAS DISTRIBUTION ACCESS RULE D/A 2016	265.9								265.9		
14.	AVERAGE USE TRUE-UP V/A	(4,108.3)							(4,108.3)			
15.	POST-RETIREMENT TRUE-UP V/A	(4,393.9)									(4,393.9)	
16.	2017 CUSTOMER CARE CIS RATE SMOOTHING D/A	(59.6)								(59.6)		
17.	2016 CUSTOMER CARE CIS RATE SMOOTHING D/A	(14.6)								(14.6)		
18.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A	20.8								20.8		
19.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A	53.9								53.9		
20.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A	85.3								85.3		
21.	GREEN HOUSE GAS EMISSIONS IMPACT D/A	0.0			0.0					0.0		
22.	UNABSORBED DEMAND COST D/A	0.0					0.0					
23.	ELECTRIC PROGRAM EARNINGS SHARING D/A	(692.6)									(692.6)	
24.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8						0.0			4,435.8	
25.	DAWN ACCESS COSTS D/A	(910.7)										(910.7)
26.	CONSTANT DOLLAR NET SALVAGE ADJ. D/A	6,468.3							6,468.3			
27.	EARNINGS SHARING MECHANISM	(23,973.4)						0.0			(23,973.4)	
	TOTAL	5,030.2	1,107.3	0.0	726.6	7,503.0	15,801.9	0.0	2,360.0	351.7	(21,909.6)	(910.7)
	ALLOCATION											
1.1	RATE 1	2,787.3	567.2	0.0	303.5	3,654.0	8,742.7	0.0	3,902.9	324.5	(14,325.7)	(381.7)
1.2	RATE 6	3,874.0	455.4	0.0	301.0	3,443.7	6,810.0	0.0	(784.9)	27.1	(6,000.5)	(377.9)
1.3	RATE 9	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	(2.0)	0.0	(0.3)	(0.0)
1.4	RATE 100	(4.5)	0.1	0.0	0.1	0.5	1.7	0.0	55.0	0.0	(61.9)	0.0
1.5	RATE 110	(28.7)	40.6	0.0	51.1	176.5	79.6	0.0	(19.3)	0.0	(290.3)	(67.0)
1.6	RATE 115	(188.4)	6.4	0.0	32.6	0.2	15.5	0.0	(86.4)	0.0	(118.6)	(38.1)
1.7	RATE 125	(639.9)	0.0	0.0	0.0	0.0	0.0	0.0	(417.2)	0.0	(222.7)	0.0
1.8	RATE 135	(6.8)	5.0	0.0	4.2	0.0	0.0	0.0	1.1	0.0	(12.4)	(4.7)
1.9	RATE 145	(194.8)	1.6	0.0	3.0	24.9	0.0	0.0	(194.2)	0.0	(25.1)	(4.9)
1.10	RATE 170	(4.1)	10.5	0.0	20.0	72.0	0.0	0.0	(51.1)	0.0	(32.4)	(23.0)
1.11	RATE 200	231.6	20.5	0.0	11.1	131.3	152.3	0.0	(17.1)	0.0	(53.4)	(13.3)
1.12	RATE 300	(34.6)	0.0	0.0	0.0	0.0	0.0	0.0	(26.8)	0.0	(7.8)	0.0
1.13	RATE 332	(758.5)							0.0		(758.5)	
1.		5,030.2	1,107.3	0.0	726.6	7,503.0	15,801.9	0.0	2,360.0	351.7	(21,909.6)	(910.7)

ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	BUNDLED ANNUAL DELIVERIES
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:												
RATE 1	- SYSTEM SALES	2,673.6	553.0	0.0	289.9	3,490.1	8,350.7	0.0	3,727.8	310.0	(13,683.3)	(364.6)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	42.2			5.8	69.4	166.1	0.0	74.2	6.2	(272.2)	(7.3)
	- DAWN T-SERVICE	3.0			0.4	4.9	11.7	0.0	5.2	0.4	(19.2)	(0.5)
	- WBT	68.6	14.2		7.4	89.5	214.2	0.0	95.6	8.0	(351.0)	(9.4)
RATE 6	- SYSTEM SALES	2,343.5	337.0	0.0	176.7	2,021.2	3,997.0	0.0	(460.7)	15.9	(3,521.9)	(221.8)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	620.0			54.6	624.5	1,235.0	0.0	(142.3)	4.9	(1,088.2)	(68.5)
	- DAWN T-SERVICE	87.3			7.7	87.9	173.9	0.0	(20.0)	0.7	(153.2)	(9.7)
	- WBT	823.2	118.4		62.1	710.0	1,404.1	0.0	(161.8)	5.6	(1,237.2)	(77.9)
RATE 9	- SYSTEM SALES	(2.3)	0.0	0.0	0.0	0.0	0.0	0.0	(2.0)	0.0	(0.3)	(0.0)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- DAWN T-SERVICE	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	(3.5)	0.1	0.0	0.1	0.4	1.3	0.0	42.9	0.0	(48.4)	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(0.2)			0.0	0.0	0.1	0.0	2.3	0.0	(2.5)	0.0
	- DAWN T-SERVICE	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	(0.8)	0.0		0.0	0.1	0.3	0.0	9.8	0.0	(11.0)	0.0
RATE 110	- SYSTEM SALES	1.9	6.6	0.0	3.4	11.9	5.4	0.0	(1.3)	0.0	(19.6)	(4.5)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(35.1)			25.9	89.4	40.3	0.0	(9.8)	0.0	(147.1)	(33.9)
	- DAWN T-SERVICE	(5.3)			3.9	13.5	6.1	0.0	(1.5)	0.0	(22.2)	(5.1)
	- WBT	9.8	34.1		17.9	61.6	27.8	0.0	(6.7)	0.0	(101.4)	(23.4)
RATE 115	- SYSTEM SALES	(0.0)	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	0.0
	- T-SERVICE EXCL WBT	(162.1)			27.1	0.2	12.9	0.0	(71.9)	0.0	(98.7)	(31.7)
	- DAWN T-SERVICE	(12.7)			2.1	0.0	1.0	0.0	(5.6)	0.0	(7.7)	(2.5)
	- WBT	(13.6)	6.4		3.3	0.0	1.6	0.0	(8.8)	0.0	(12.1)	(3.9)
RATE 135	- SYSTEM SALES	(0.2)	0.4	0.0	0.2	0.0	0.0	0.0	0.0	0.0	(0.5)	(0.2)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(4.4)			1.6	0.0	0.0	0.0	0.4	0.0	(4.6)	(1.8)
	- DAWN T-SERVICE	(0.1)			0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.0)
	- WBT	(2.1)	4.6		2.4	0.0	0.0	0.0	0.6	0.0	(7.1)	(2.7)
RATE 145	- SYSTEM SALES	(28.5)	0.8	0.0	0.4	3.7	0.0	0.0	(29.0)	0.0	(3.8)	(0.7)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(123.0)			1.8	15.6	0.0	0.0	(121.6)	0.0	(15.8)	(3.1)
	- DAWN T-SERVICE	(18.6)			0.3	2.4	0.0	0.0	(18.4)	0.0	(2.4)	(0.5)
	- WBT	(24.6)	0.7		0.4	3.2	0.0	0.0	(25.1)	0.0	(3.2)	(0.6)
RATE 170	- SYSTEM SALES	2.5	4.0	0.0	2.1	7.5	0.0	0.0	(5.3)	0.0	(3.4)	(2.4)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- DAWN T-SERVICE	(0.5)			0.7	2.5	0.0	0.0	(1.8)	0.0	(1.1)	(0.8)
RATE 200	- SYSTEM SALES	178.5	16.3	0.0	8.6	100.9	117.1	0.0	(13.1)	0.0	(41.0)	(10.2)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	7.4			0.4	4.6	5.3	0.0	(0.6)	0.0	(1.9)	(0.5)
	- DAWN T-SERVICE	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	45.6	4.2		2.2	25.8	29.9	0.0	(3.4)	0.0	(10.5)	(2.6)
Unbundled Services:												
RATE 125		(639.9)	0.0	0.0	0.0	0.0	0.0	0.0	(417.2)	0.0	(222.7)	
RATE 300		(34.6)	0.0	0.0	0.0	0.0	0.0	0.0	(26.8)	0.0	(7.8)	
RATE 332		(758.5)							0.0		(758.5)	
		5,030.1	1,107.3	0.0	726.6	7,503.0	15,801.9	0.0	2,359.9	351.7	(21,909.6)	(910.7)

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	BUNDLED ANNUAL DELIVERIES
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)
Bundled Services:												
RATE 1	- SYSTEM SALES	0.0591	0.0122	0.0000	0.0064	0.0771	0.1845	0.0000	0.0824	0.0068	(0.3023)	(0.0081)
	- 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	0.0468			0.0064	0.0771	0.1845	0.0000	0.0824	0.0068	(0.3023)	(0.0081)
	- DAWN T-SERVICE	0.0468			0.0064	0.0771	0.1845	0.0000	0.0824	0.0068	(0.3023)	(0.0081)
	- WESTERN T-SERVICE	0.0591	0.0122		0.0064	0.0771	0.1845	0.0000	0.0824	0.0068	(0.3023)	(0.0081)
RATE 6	- SYSTEM SALES	0.0849	0.0122	0.0000	0.0064	0.0733	0.1449	0.0000	(0.0167)	0.0006	(0.1277)	(0.0080)
	- 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	0.0727			0.0064	0.0733	0.1449	0.0000	(0.0167)	0.0006	(0.1277)	(0.0080)
	- DAWN T-SERVICE	0.0727			0.0064	0.0733	0.1449	0.0000	(0.0167)	0.0006	(0.1277)	(0.0080)
	- WESTERN T-SERVICE	0.0849	0.0122		0.0064	0.0733	0.1449	0.0000	(0.0167)	0.0006	(0.1277)	(0.0080)
RATE 9	- SYSTEM SALES	(9.1216)	0.0122	0.0000	0.0064	0.0004	0.0317	0.0000	(7.8730)	0.0019	(1.2211)	(0.0801)
	- 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
	- DAWN T-SERVICE	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	(0.3771)	0.0122	0.0000	0.0064	0.0457	0.1449	0.0000	4.6427	0.0000	(5.2290)	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	(0.3893)			0.0064	0.0457	0.1449	0.0000	4.6427	0.0000	(5.2290)	0.0000
	- DAWN T-SERVICE	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	(0.3771)	0.0122		0.0064	0.0457	0.1449	0.0000	4.6427	0.0000	(5.2290)	0.0000
RATE 110	- SYSTEM SALES	0.0035	0.0122	0.0000	0.0064	0.0221	0.0100	0.0000	(0.0024)	0.0000	(0.0364)	(0.0084)
	- 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	(0.0087)			0.0064	0.0221	0.0100	0.0000	(0.0024)	0.0000	(0.0364)	(0.0084)
	- DAWN T-SERVICE	(0.0087)			0.0064	0.0221	0.0100	0.0000	(0.0024)	0.0000	(0.0364)	(0.0084)
	- WESTERN T-SERVICE	0.0035	0.0122		0.0064	0.0221	0.0100	0.0000	(0.0024)	0.0000	(0.0364)	(0.0084)
RATE 115	- SYSTEM SALES	(0.0431)	0.0122	0.0000	0.0064	0.0000	0.0031	0.0000	(0.0340)	0.0000	(0.0233)	(0.0075)
	- 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	(0.0383)			0.0064	0.0000	0.0031	0.0000	(0.0170)	0.0000	(0.0233)	(0.0075)
	- DAWN T-SERVICE	(0.0383)			0.0064	0.0000	0.0031	0.0000	(0.0170)	0.0000	(0.0233)	(0.0075)
	- WESTERN T-SERVICE	(0.0261)	0.0122		0.0064	0.0000	0.0031	0.0000	(0.0170)	0.0000	(0.0233)	(0.0075)
RATE 135	- SYSTEM SALES	(0.0056)	0.0122	0.0000	0.0064	0.0000	0.0000	0.0000	0.0016	0.0000	(0.0187)	(0.0072)
	- 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	(0.0179)			0.0064	0.0000	0.0000	0.0000	0.0016	0.0000	(0.0187)	(0.0072)
	- DAWN T-SERVICE	(0.0179)			0.0064	0.0000	0.0000	0.0000	0.0016	0.0000	(0.0187)	(0.0072)
	- WESTERN T-SERVICE	(0.0056)	0.0122		0.0064	0.0000	0.0000	0.0000	0.0016	0.0000	(0.0187)	(0.0072)
RATE 145	- SYSTEM SALES	(0.4138)	0.0122	0.0000	0.0064	0.0540	0.0000	0.0000	(0.4212)	0.0000	(0.0545)	(0.0107)
	- 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	(0.4260)			0.0064	0.0540	0.0000	0.0000	(0.4212)	0.0000	(0.0545)	(0.0107)
	- DAWN T-SERVICE	(0.4260)			0.0064	0.0540	0.0000	0.0000	(0.4212)	0.0000	(0.0545)	(0.0107)
	- WESTERN T-SERVICE	(0.4138)	0.0122		0.0064	0.0540	0.0000	0.0000	(0.4212)	0.0000	(0.0545)	(0.0107)
RATE 170	- SYSTEM SALES	0.0076	0.0122	0.0000	0.0064	0.0230	0.0000	0.0000	(0.0163)	0.0000	(0.0104)	(0.0074)
	- 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	(0.0047)			0.0064	0.0230	0.0000	0.0000	(0.0163)	0.0000	(0.0104)	(0.0074)
	- DAWN T-SERVICE	(0.0047)			0.0064	0.0230	0.0000	0.0000	(0.0163)	0.0000	(0.0104)	(0.0074)
	- WESTERN T-SERVICE	0.0076	0.0122		0.0064	0.0230	0.0000	0.0000	(0.0163)	0.0000	(0.0104)	(0.0074)
RATE 200	- SYSTEM SALES	0.1336	0.0122	0.0000	0.0064	0.0755	0.0876	0.0000	(0.0098)	0.0000	(0.0307)	(0.0076)
	- 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	0.1213			0.0064	0.0755	0.0876	0.0000	(0.0098)	0.0000	(0.0307)	(0.0076)
	- DAWN T-SERVICE	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.1336	0.0122		0.0064	0.0755	0.0876	0.0000	(0.0098)	0.0000	(0.0307)	(0.0076)
Unbundled Services:												
RATE 125	- All	(6.6210)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(4.3170)	0.0000	(2.3040)	0.0000
	- Customer-specific **											0.0000
RATE 300	- All	(266.5374)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(206.5128)	0.0000	(60.0246)	0.0000
	- Customer-specific **											
RATE 332	- All	(2.38)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	(2.3824)	0.0000

Notes:

* Unit Rates derived based on 2017 actual volumes

Enbridge Gas Distribution Inc.
2017 Deferral and Variance Account Clearing
Bill Adjustment in January 2019 for Typical Customers

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
			Unit Rates				Bill Adjustment			
	GENERAL SERVICE	Annual Volume	Sales	Ontario TS	Dawn TS	Western TS	Sales Customers	Ontario TS Customers	Dawn TS Customers	Western TS Customers
		m3	cents/m3	cents/m3	cents/m4	cents/m3	$	$	$	$
1.1	**RATE 1 RESIDENTIAL**									
1.2	Heating & Water Heating	2,400	0.0591	0.0468	0.0468	0.0591	1.4	1.1	1.1	1.4
2.1	**RATE 6 COMMERCIAL**									
2.2	General Use	43,285	0.0849	0.0727	0.0727	0.0849	37	31	31	37
	CONTRACT SERVICE									
3.1	**RATE 100**									
3.2	Industrial - small size	339,188	(0.3771)	(0.3893)	0.0000	(0.3771)	(1,279)	(1,321)	-	(1,279)
4.1	**RATE 110**									
4.2	Industrial - small size, 50% LF	598,568	0.0035	(0.0087)	(0.0087)	0.0035	21	(52)	(52)	21
4.5	Industrial - avg. size, 75% LF	9,976,121	0.0035	(0.0087)	(0.0087)	0.0035	352	(867)	(867)	352
5.1	**RATE 115**									
5.2	Industrial - small size, 80% LF	4,471,609	(0.0431)	(0.0383)	(0.0383)	(0.0261)	(1,925)	(1,712)	(1,712)	(1,166)
6.1	**RATE 135**									
6.2	Industrial - Seasonal Firm	598,567	(0.0056)	(0.0179)	(0.0179)	(0.0056)	(34)	(107)	(107)	(34)
7.1	**RATE 145**									
7.2	Commercial - avg. size	598,568	(0.4138)	(0.4260)	(0.4260)	(0.4138)	(2,477)	(2,550)	(2,550)	(2,477)
8.1	**RATE 170**									
8.2	Industrial - avg. size, 75% LF	9,976,121	0.0076	(0.0047)	(0.0047)	0.0076	755	(464)	(464)	755

Notes:
Col. 7 = Col. 2 x Col. 3
Col. 8 = Col. 2 x Col. 4
Col. 9 = Col. 2 x Col. 5
Col. 10 = Col. 2 x Col. 6

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. As a result of and as noted in the EB-2017-0306/0307 amalgamation application filed by Enbridge and Union Gas, a Benchmarking Study is not currently being performed.

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 to 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 4, Schedule 1 and within Exhibit D, Tab 5.

4. Enbridge also agreed to hold an Annual Stakeholder Day each year during the Custom IR term. Enbridge held its fourth Stakeholder Day on June 6, 2018 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.

a. The Gas Supply Planning Memorandum for 2018 was filed within the EB-2017-0086, 2018 Rate Proceeding.
b. The GTA project was complete in March 2016, with the exception of Ashtonbee Station which went in service in June 2017. Enbridge included its final update report on the GTA project in the EB-2017-0102, 2016 ESM proceeding (Exhibit D-1-2).
c. The WAMS project was complete and in use in October 2016. Enbridge included its final update report on the GTA project in the EB-2017-0102, 2016 ESM proceeding (Exhibit D-3-1).
d. Information on the progress of the System Integrity program is filed in this proceeding at Exhibit D-1-2.
e. Information on the progress of the Asset Management Plan is filed in this proceeding at Exhibit D-1-4.

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

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 the 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 those 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 to continue to address known issues and proactively maintain a safe and reliable distribution and storage system. Over the period of 2014-2017, significant efforts were focused on:
   - Gaining a better understanding of the health and condition of assets as it pertains to risk 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, Enbridge's actual System Integrity spend within 2017 was $121.4M versus the $141.1M which the Board approved within the EB-2012-0459 proceeding. It should be noted that this spend does not include the GTA project.

Exhibit Reference	Description	2017 ACT	2017 IRM	2017 VAR	2014-2017 CUMULATIVE ACT	2014-2017 CUMULATIVE IRM	2014-2017 CUMULATIVE VAR
B2-5-2	Main Replacement	21,612	22,100	488	117,116	92,882	(24,234)
B2-5-3	Service Replacement	24,469	41,227	16,758	91,763	128,604	36,841
B2-5-4	Station Replacement	23,685	24,517	832	86,521	99,466	12,945
B2-5-5	Other System Integrity and Reliability	37,544	35,810	(1,734)	159,068	156,078	(2,990)
B2-5-6	System Integrity Direct Resource Costs	14,116	17,449	3,333	59,480	72,636	13,156
	Total System Integrity & Reliability	**121,426**	**141,103**	**19,677**	**513,948**	**549,666**	**35,718**

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 SIR portfolio for 2017 was developed using Enbridge's Asset Management Framework and resulted in portfolio prioritization using risk based assessments.

9. The 2017 $19.6M underspend variance represents a 13.9% variance versus the approved budget of $141.1M. The following paragraphs set out high-level explanations for variances.

10. Mains expenditures in 2017 were consistent with the amount approved in the Custom IR case. However, cumulatively over the 2014 to 2017 period, Enbridge has spent around $24M more than the approved budget on mains replacement.

11. Service replacement expenditures in 2017 were around $16.8M below the approved budget, in part because of reprioritization of projects.

12. Stations expenditures in 2017 were consistent with the amount approved in the Custom IR case.

13. SIR Direct Resource Costs: Departmental labour costs are primarily capitalized salaries and employee expenses. The favorable variance is due to a reduced workforce. The Company committed in its IR application to find productivity in this area. Targeted hiring practices in place have led to delays in filling vacancies which also factors into the variance.

14. As shown below, Enbridge's actual Reinforcement and Relocation spend within 2017 was $8.1M versus the $21.3M which the Board approved within the EB-2012-0459 proceeding.

Exhibit Reference	Description	2017 ACT	2017 IRM	2017 VAR	2014-2017 CUMULATIVE ACT	2014-2017 CUMULATIVE IRM	2014-2017 CUMULATIVE VAR
B2-3-1	Reinforcements	4,683	8,743	4,060	20,872	45,838	24,966
B2-4-1	Relocations	3,472	12,603	9,131	23,037	53,828	30,791
	Total	**8,155**	**21,346**	**13,191**	**43,909**	**99,666**	**55,757**

15. The variances were driven in large part by the timing of projects, and the mix of the cost recovery mechanism, whereby a greater percentage of projects resulted from non-municipal infrastructure builds, with 100% cost recovery.

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. On November 2017, Enbridge and Union Gas filed for approval to amalgamate and to defer rate rebasing from 2019 to 2029 under EB-2017-0306/0307. As indicated in the application, the Company will not be completing a benchmarking study at this time, and intends to address this commitment as part of its next rebasing application.

Witness: R. Torul

STATUS OF ASSET MANAGEMENT PLANNING PROCESS

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

2017 Progress Update

2. The Company has made significant progress in the design and implementation of its AM system over the past years. The Company's AM process now includes all of the Company's assets. The AM system is an important input for budgeting decisions and supports the optimization of all asset related investments over a multi-year planning horizon. The Company has procured multiple software solutions to enable the end-to-end process.

3. The 2018-2027 Asset Plan was filed in response to an interrogatory in the MAADs application EB-2017-0306/0307. This is the first version of the 10 year Asset Plan applying the new methodology. It uses condition information and quantitative risk assessments to support the Company's understanding of asset health and risk. This

information is used to manage the lifecycle of the assets and optimize capital spend. The 2019-2028 Asset Plan is currently in progress.

4. The Company has an aspirational goal to meet the requirements of the ISO 55000 standard. Enbridge has engaged an ISO 55000 certified assessor, KPMG, to benchmark the Company's overall approach to AM, provide a gap analysis, and recommendations on next steps to further advance its maturity. Follow up assessments will be completed as required to continually understand the Company's progress in relation to ISO 55000 requirements.

PRODUCTIVITY INITIATIVES SUMMARY

Introduction

1. The purpose of this evidence is to present the 2017 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. The status of the Benchmarking Report is set out at Exhibit D, Tab 1, Schedule 3.

2. 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 4th year of the Custom IR term, Enbridge has found ways to achieve most, but not all of the embedded productivity savings targets identified in the Custom IR evidence;
   - (v) Enbridge has also found other productivity savings, reported through incremental initiatives;
   - (vi) In total, productivity savings during the 4th year of the Custom IR term are close to the committed levels and the Company will work to continue to sustain and find ongoing opportunities;

Witnesses: M. Suarez
F. Zhao

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

3. 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

<u>Background</u>

4. The Company issued its initial 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 2017 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.

5. Tables 1 and 2 show the Core Capital and Other O&M amounts approved over the Custom IR term with emphasis on the 2017 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 Savings	(26.2)	(28.7)	(27.1)	(35.2)	(45.3)	(162.1)
Less: Variable Costs	(25.1)	(63.0)	(75.9)	(50.0)	(50.0)	(264.0)
Approved Core Capital Expenditures	443.8	446.6	441.9	441.9	441.9	2,216.1

Table 2:

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

6. This evidence will describe the work items, initiatives, and programs sustained from 2014, 2015, and 2016, including those newly implemented by the Company in 2017 to deliver on the embedded reductions of $88.1 million ($35.2 million in capital, $39.3 million in O&M and $13.6 O&M OEB Adjustment). It will also describe the status of the excluded variable capital costs ($50.0 million) which were uncertain cost requirements excluded from the proposed capital amount.

Witnesses: M. Suarez
F. Zhao

<u>Embedded O&M and Capital Reductions (Productivity)</u>

7. 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.

8. Table 3 lists the embedded productivity reductions in 2017 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:

2017 Embedded O&M and Capital Reductions		Embedded Commitment ($M)
1	O&M: Merit Increase	(3.5)
2	O&M: Employee Benefit	(3.3)
3	O&M: Incremental cost to service new customers	(1.8)
4	O&M: Incremental safety and Integrity work	(9.5)
5	O&M: External contractor rate increases	(2.0)
6	O&M: Increased volume of locates-compliance with Bill 8	(4.5)
7	O&M: FTEs	(8.8)
8	O&M: Bad Debt expenses	(5.9)
9	Total O&M Productivity Guarantee	(39.3)
10	Capital: Customer Attachments	(24.6)
11	Capital: Departmental Labour	(4.2)
12	Capital: Other	(6.4)
13	Total Capital Productivity Guarantee	(35.2)

9. 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 for 2017.

10. 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 2017 results had a weighted increase of 2.4% in an effort to balance financial pressures and the Company's competitive position in the market. Total savings for merit increase were about $0.5 million which was $3.0 million short of the embedded reduction for 2017.

11. Although benefit costs were expected to rise, the approved budget reflected an increase of only 2%. In 2017, actuals were lower than budget due to workforce reduction, and $1.9 million savings were achieved above the $3.3 million in committed savings. The Company remains committed to managing to the lower rate of increase.

12. 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 anticipated as a result of a policy change effective January 1, 2016 requiring builders to contact Enbridge for residential construction heat activation as 3rd party activations are no longer permitted. The increased costs were partially offset by customer contributions for the FSBI inspections. In 2017, $0.5 million of the $1.8 million in committed savings was achieved.

13. Pipeline Integrity, Distribution Operations, Engineering continued to achieve operational efficiencies throughout 2017. The Integrity group worked very closely with its vendors to address business constraints and operational challenges, enabling savings of about $0.24 million for inspection work in 2017. Distribution Operations continues to achieve productivity savings from its prior reorganization to functional lines of accountability compared with the traditional regional structure

(geographically based organization), as well as to look for opportunities for process improvement that will bring sustainable savings. For example, the change initiated in 2014 on the plant leak survey will continue to provide benefits to 2019. The initiative took an initial leak survey that had a target completion date of 12 months after the installation of a pressure tested gas main or gas service, assessed the risk, and incorporated it into the 5-year leak survey program with no change to the risk profile. This change improved the ability to provide leak survey support for activities outside the standard programs and also reduced the contractor unit costs because of increased standard survey volume. Another process improvement is the change in the tagging process of initial inspection for new premises. The new procedure allows B-tags to be issued for minor deficiencies instead of reject tags. As such, appliance installers are able to clear the tags, improve customer satisfaction with builders, and eliminate follow up field visits from EGD crews. These efforts contributed to the $1.7M in identified savings in the areas of Operations, Incremental Safety, and Integrity work.

14. By centralizing the oversight of contract management functions, the Company has generated external contractor savings estimated at $0.4 million in 2017.

15. 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 3% over 2016 volumes, the actual increase was 24%. However, EGD has been able to manage and reduce costs, as described below. The associated embedded productivity commitment was $4.5 million and the total savings in this area amounted to $7.7M.

16. In an effort to manage costs, 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 10% 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 $3.6 million in 2017.

17. In addition to the above, Damage Prevention implemented a Dedicated Locator Model in 2017 that focuses on the unique requirements of large infrastructure projects which include Telecommunication and Municipal Capital work. The model employs an ownership approach for the Excavators by having dedicated resources (locators) from Enbridge approved vendors embedded with the excavator’s crews. While Excavators benefit from their efficient locate schedule which reduce crew downtime, the Company benefits from better forecasting and maintains timely locate delivery with no additional locate costs. This approach achieved $3.8 million O&M savings in 2017.

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 2.17 in 2016 to 1.81 in 2017 representing a 16% 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 2017 budgeted level by 346 positions. FTE savings are the salary and wage reductions expected to be sustained throughout the Custom IR term and are exclusive of severance costs. 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. The combination of these efforts resulted in O&M FTE savings of $16.1 million and Capitalized DLC savings of $1.4 million.

20. Bad debt expense was held flat at $9.5 million within the 2017 O&M budget, although indications were that this expense would be around $15.4 million on the basis of commodity forecasts and the overall level of consumer indebtedness. Actual 2017 bad debt expenses were $5.4 million, $4.1M below budget, resulting in total savings of $10 million. The Company has implemented more targeted collections criteria that improved collections performance and driven reductions in bad debt expense. The lower bills in 2017 also contributed to the lower bad debt amount.

21. Embedded productivity commitments in the area of Customer Attachment capital were partially met in 2017. The embedded productivity savings of $24.6M was not achieved because actual spending in this area exceeded the budget by $7.7M. Customer Attachment capital was overspent due to the different attachment profiles by customer segment and geographical mix. Third party fees, material costs and pipeline contractor labor costs per customer continue to increase.

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 continues to utilize an internal working group made up of various departments to manage and mitigate third party fees that impact construction costs.

23. An additional category of Capital savings exists in 2017 which stems from the Company's commitment to hold its 2017 and 2018 capital spend to the 2016 level. The additional $6.4M in overall embedded savings is not associated with any particular area of spend, but serves to increase the overall capital cost savings commitment.

24. Table 4 summarizes the estimated savings for each embedded productivity area in O&M and capital relative to the guaranteed amounts.

Table 4:

2017 Embedded O&M and Capital Reductions		Embedded Commitment ($M)	Actual ($M)
1	O&M: Merit Increase	(3.5)	(0.5)
2	O&M: Employee Benefit	(3.3)	(5.2)
3	O&M: Incremental cost to service new customers	(1.8)	(0.5)
4	O&M: Incremental safety and Integrity work	(9.5)	(1.7)
5	O&M: External contractor rate increases	(2.0)	(0.4)
6	O&M: Increased volume of locates-compliance with Bill 8	(4.5)	(7.7)
7	O&M: FTEs	(8.8)	(16.1)
8	O&M: Bad Debt expenses	(5.9)	(10.0)
9	Total O&M Productivity Guarantee	(39.3)	(42.2)
10	Capital: Customer Attachments	(24.6)	(17.2)
11	Capital: Departmental Labour	(4.2)	(1.4)
12	Capital: Other	(6.4)	-
13	Total Capital Productivity Guarantee	(35.2)	(18.5)
14	Total Embedded O&M & Capital Reductions	(74.5)	(60.7)

25. Of the $39.3 million guaranteed O&M savings, cost mitigation efforts achieved $42.2 million most effectively through FTE management. Of the $35.2 million guaranteed capital savings, cost mitigation efforts achieved $18.5 million. Relative to the total O&M and capital guaranteed savings, the Company achieved $60.7 million of the $74.5 million target.

<u>Incremental Productivity Initiatives</u>

26. O&M and capital 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. There were no OEB commitments for incremental initatives but these additional efforts serve to augment embedded O&M and Capital Savings.

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 eighty (180) 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 $16.1 million in O&M FTE reductions and $1.4 million in capital DLC savings identified in the earlier part of this evidence, other labour optimization efforts were pursued that enabled the shedding of costs through the absorption of work by existing labour capacity, the reallocation of tasks, the targeted hiring of specific skill sets to offset outside services, and the management of overtime hours. For example, in the Technical Training group, by hiring three employees with specific skillsets in 2014, the group was able to save outside services costs by developing training material internally instead. Also the conversion of selected EHS courses from instructor-led to web-based, saved significant employee travel time and related costs, including outside vendor training delivery costs as well as cost reduction from printed material. The savings from these efficiencies have not only been sustained but have also grown from $0.14 million in O&M in 2015 to $0.40 million in 2017. Another example is the Small Claims Litigation Insourcing initiative which has built on its initial savings $0.05 million from 2014 through more streamlined processes, more experience and knowledge gained. This initiative has saved $0.95 million in O&M in 2017. The labour optimization savings from these types of initiatives were estimated at $2.3 million in O&M and $0.7 million in capital.

30. Process Optimization initiatives relate to changes in the way work is organized to achieve efficiencies. These include system changes, more efficient work flows, streamlined tools, and the elimination of redundant reports. The savings from these types of initiatives were estimated at $8.2 million in O&M and $2.5 million in capital. For example, the e-bill initiative continues to provide cumulative sustainable savings starting from $0.4 million in 2014 and growing to $3.5 million in 2017. 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. Starting in 2016, Customer Care improved the online process of move

requests, significantly reducing call volumes and back office administration. Similarly, by enhancing the messages in the Interactive Voice Response (IVR) system, customers are able to obtain answers through an automated system, saving $1.4 million. New in 2017 is the Customer Satisfaction Research initiative which assessed the survey instrument and focused on key driver analysis to remove questions without compromising the quality of the research. This resulted in lower third party O&M costs associated with reduced time spent on interviewing, data processing, editing and analyzing, and reporting.

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. The largest savings in 2017 from a sustained initiative relates to Storage Operation. With long-term planning for well drilling, workovers, and abandonments, various cost effective options were assessed. Significant savings were achieved through the avoidance of high rental costs for mills, steel plates, drill pipe and other working material, by instead investing capital to purchase the needed equipment for current and future work. The initiative brought overall savings of $1.4 million in capital and $0.05 million in O&M. This group of initiatives achieved an estimated savings of $3.3 million in O&M and $2.0 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, the policy change made to the Company’s Carbon Monoxide (“CO”) Alarm Response Policy continues to offer sustainable savings growing from $0.13M in 2014 to $0.3M in

2017. Another example is the warning tag improvement initiative which was implemented in 2014 in order to improve the work efficiency by reducing the need for subsequent field follow-ups. By implementing this policy, the company has seen approximately 4,000 fewer field visits, saving $0.2M each year. Savings in this category of initiatives amounted to $0.9M in O&M and $0.6M in capital.

33. Incremental O&M savings from sustained productivity actions in 2017 are estimated at $14.6 million. Although a small amount of savings are from new initiatives relating to software maintenance and purchase savings, the bulk of the savings is from the sustainment of 2014, 2015 and 2016 productivity initiatives. As shown in Table 5, the Company reported $12.9 million in savings from incremental O&M initiatives in 2016; 85% of those initiatives were sustained, and the total savings from those initiatives grew to $14.6 million in 2017. 2017 results have demonstrated productivity sustainment and growth in the 4th year of the Custom IR term.

Table 5:

2017 Incremental O&M Productivity Initiatives				
Amounts reported in millions	**2016 Savings on Sustained Initiatives**	**2017 Savings on Sustained Initiatives**	**2017 Savings on New Initiatives**	**Total 2017**
Labour Optimization	(2.0)	(2.3)	(0.00)	(2.3)
Process Optimization	(5.9)	(8.1)	(0.03)	(8.2)
Materials/Space/Equipment Rationalization	(4.1)	(2.5)	(0.75)	(3.3)
Policy Change and Improvements	(0.9)	(0.9)	-	(0.9)
Total Reductions from Incremental O&M Initiatives	(12.9)	(13.9)	(0.8)	(14.6)

Witnesses: M. Suarez
F. Zhao

34. Sustained capital productivity savings increased by $0.5M from 2016. Additional process optimization initiatives in 2017 raised capital savings further to total $5.8M. Capital savings serve to free up amounts in the capital budget to be allocated to other projects enabling the optimization of capital resources.

Table 6:

2017 Incremental Capital Productivity Initiatives				
Amounts reported in millions	**2016 Savings on Sustained Initiatives**	**2017 Savings on Sustained Initiatives**	**2017 Savings on New Initiatives**	**Total 2017**
Labour Optimization	(1.3)	(0.7)	-	(0.7)
Process Optimization	(2.0)	(2.0)	(0.4)	(2.5)
Materials/Space/Equipment Rationalization	(1.3)	(2.0)	-	(2.0)
Policy Change and Improvements	(0.3)	(0.6)	-	(0.6)
Total Reductions Available for Capital Reallocation	(4.9)	(5.4)	(0.4)	(5.8)

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, 2015 and 2016, most of the variable capital costs identified for 2017 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 2017.

Summary and Sustainability of Savings:

37. Through pooled efforts at all levels of the organization, the Company came close to achieving its embedded reductions target of $88.1 million in 2017 through the combination of savings in embedded areas of productivity and incremental productivity initiatives. Table 7 provides a breakdown of the 2017 reductions achieved within the areas identified for productivity enhancement.

Table 7:

	2017					
	O&M ($M)		Capital ($M)		Total ($M)	
	Commitment	Actual	Commitment	Actual	Commitment	Actual
Embedded	(39.3)	(42.2)	(35.2)	(18.5)	(74.5)	(60.7)
Incremental		(14.6)		(5.8)		(20.4)
OEB Adjustment	(13.6)				(13.6)	
2017 Total Savings	(52.9)	(56.8)	(35.2)	(24.3)	(88.1)	(81.2)

38. The Embedded Reductions and Incremental Initiatives are expected to continue throughout the Custom IR term. Through consistent messaging and continued

[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.

focus within the organization, the Company has seen heightened self-reporting of productivity efforts as employees and management drive to measurable results.

39. The results of the Company's commitment are detailed in Table 8 which provides the cumulative realized savings compared to cumulative committed savings in the past four years.

Table 8:

Performance Metrics

40. Table 9 and Table 10 compare 2017 operational metrics and customer service quality indicators (Exhibit D, Tab 5, Schedule 1) against baseline 2013 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. Enbridge's overall performance metrics show that it continues to offer safe and reliable service while improving its value offering to customers.

Table 9:

Operational Performance	2013	2014	2015	2016	2017	Trending
1. Employees Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	1.06	0.93	1.04	↔
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	2.43	2.17	1.81	↑
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.06	0.06	0.06	0.08	↔
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	905	991	1216	↔
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	4.84	4.60	4.76	↔

Table 10:

Customer Relationship Performance	OEB Target	2013	2014	2015	2016	2017	Trending
1. Overall Customer Satisfaction Index	NA	78%	77%	79%	79%	79%	↑
2. Call Answering Service Level (SQR)	75%	75.9%	79%	79.7%	82.4%	82.5%	↑
3. Percentage of Emergency Calls Responded to within One Hour (SQR)	90%	96.1%	96.9%	96.7%	95.2%	96.8%	↔
4. Appointments Met within the Designated Time Period (SQR)	85%	94.2%	95.1%	95.2%	95.3%	94.3%	↔
5. Time to Reschedule a Missed Appointments (SQR)	100%	95.0%	95.5%	94.8%	95.0%	96.8%	↑
6. Number of Days to Reconnect a Customer (SQR)	85%	92.6%	94.0%	94.6%	94.8%	96.2%	↑
7. Number of Calls Abandon Rate (SQR)	10%	2.8%	1.9%	2.3%	1.8%	1.8%	↑
8. Meter Reading Performance (SQR)	0.5%	0.50%	0.69%	0.51%	0.40%	0.50%	↔
9. Number of Days to provide a Written Response (SQR)	80%	94.5%	93.3%	100.0%	95.5%	100.0%	↑

↑ – Improving
↔ – Maintained
↓ – Decreasing

Witnesses: M. Suarez
F. Zhao

2018 Custom IR stakeholder Day

June 6th, 2018

Moderated by:
Kevin Culbert
Rakesh Torul

Agenda

Topic	Presenter
Opening Comments	Kevin Culbert
2017 Stakeholder Day Survey Results	Kevin Culbert
2018 Regulatory Activity	Kevin Culbert
Company Overview	Rakesh Torul
Capital Management	Steven Riccio & Deirdre Broude
Utility O&M	Sam Fallis
2017 Year End Utility Financial Results	Ryan Small
Productivity	Margarita Suarez
Gas Supply Plan	Andrew Welburn
Closing Remarks	Kevin Culbert

2017 Stakeholder Day Survey Results

- Survey sent to 12 participants
- Response rate: 33%
- Highlights:
  - 75% of the responses indicate that the conference met expectations
  - 100% of the responses indicate that the conference was well structured and organized
  - 75% of the responses indicate that the amount of time spent on each presentation is sufficient
  - 75% of the responses indicate that the information and detail for the presentation was sufficient and the presenter for each topic convey a reasonable understanding about their topic
- Comments from the survey
  - Outcome of DSM mid-term review and interplay with cap and trade compliance plans
  - Additional focus on upcoming or potential issues that EGD will be dealing with

2018 Regulatory Activity

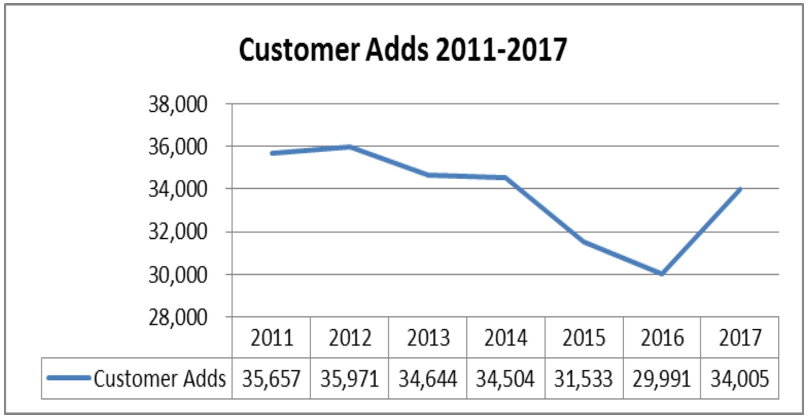
– Cap and Trade, 2018 Compliance Plan Proceeding	Current
– Nat. Gas Expansion Applications and Proceedings	
– DSM Midterm Review	
– Framework for Assessment of Gas Supply Plans	EB-2017-0129
– EGD 2017 ESM & Def/Var accounts filing	June 2018
– 2019 Cap & Trade compliance Plan filing	TBD
– EGD 2019 Rate Proceeding	TBD
– QRAM applications for July & October 2018	June & Sept 2018

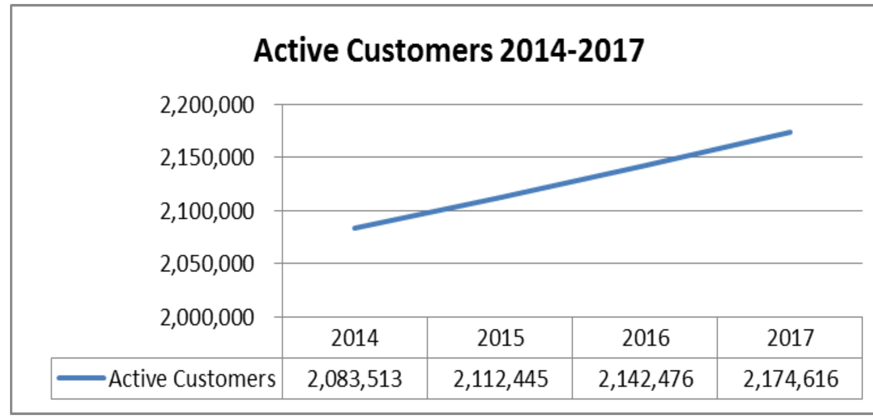
Company Overview

Rakesh Torul

2017 What we did

– 34,005 Customers Added in 2017; 2,174,616 active customers at year end 2017





– Main related work (installation, replacement and retirement)

2014	2015	2016	2017
Over 300 km	Over 400 km	Over 400 km	Over 400 km

– Volumes throughput 2014-2017

Volumes in $10^6 m^3$	2014 Actual Norm.	2014 Actual	2015 Actual Norm.	2015 Actual	2016 Actual Norm.	2016 Actual	2017 Actual Norm.	2017 Actual
Total Vols, Sales Transp.	11,297.8	12,657.6	11,299.3	11,931.8	11,309.2	10,927.1	11,763.7	11,346.5

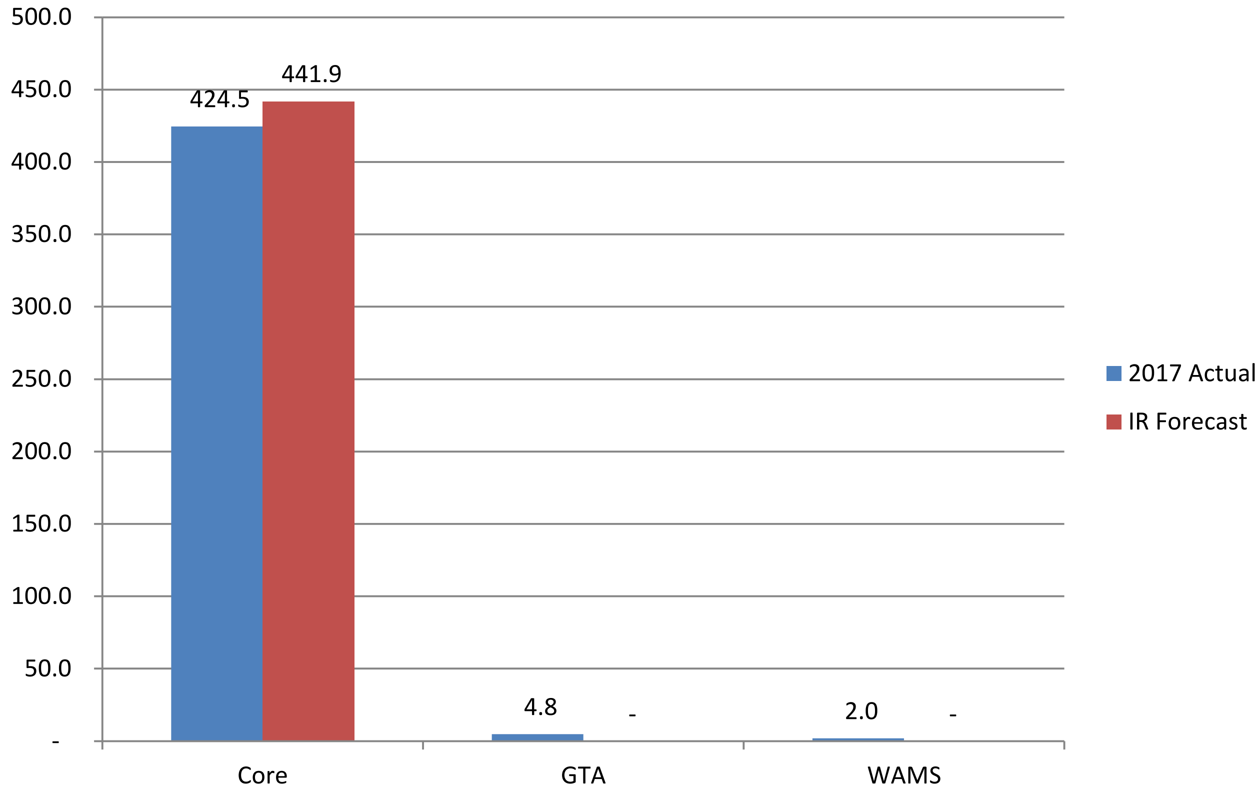
ENBRIDGE

Capital Management

Steven Riccio
Deirdre Broude

2017 – What we did: Capital Management

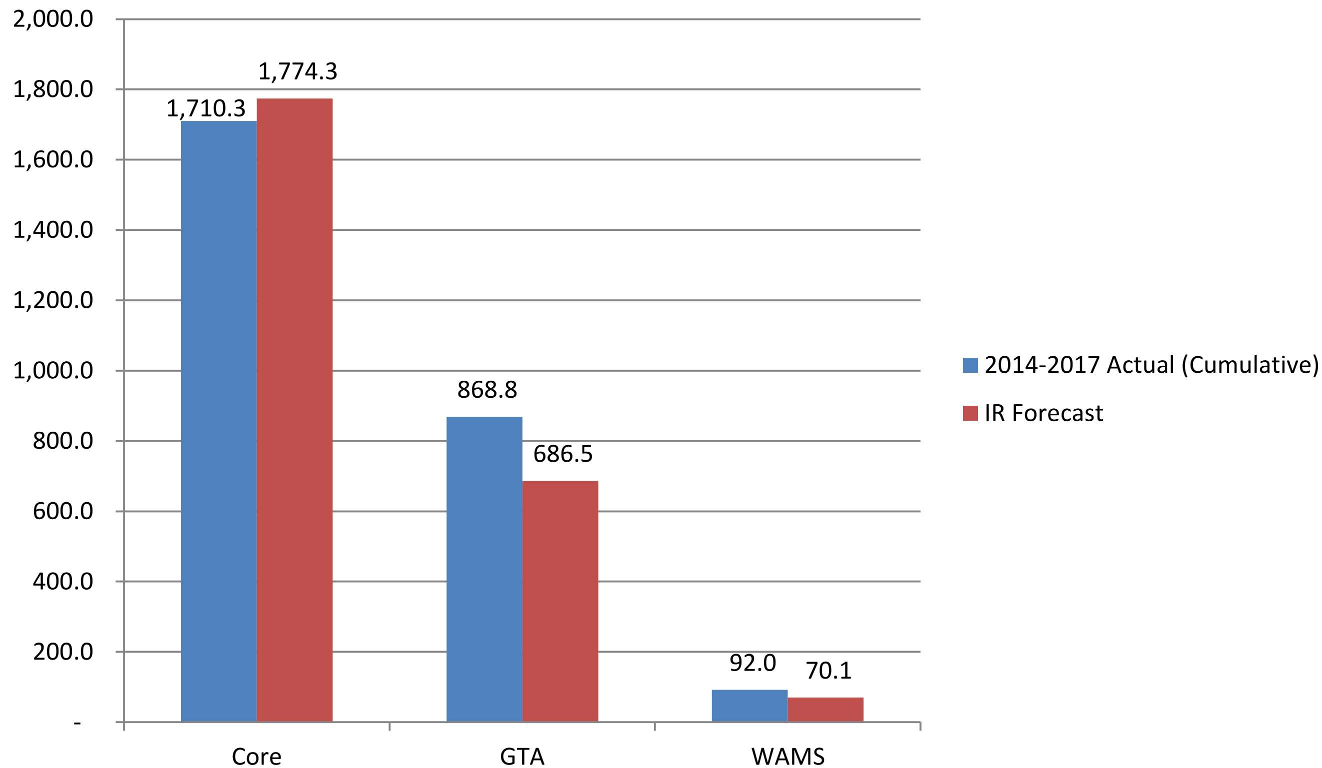
$ Millions



Total CAPEX lower spend ($10.6) due to Core ($17.4) lower than IR budget, partially offset by GTA ($4.8) and WAMS ($2.0) higher than IR budget

Capital Management: Total CAPEX Cumulative 2014-2017

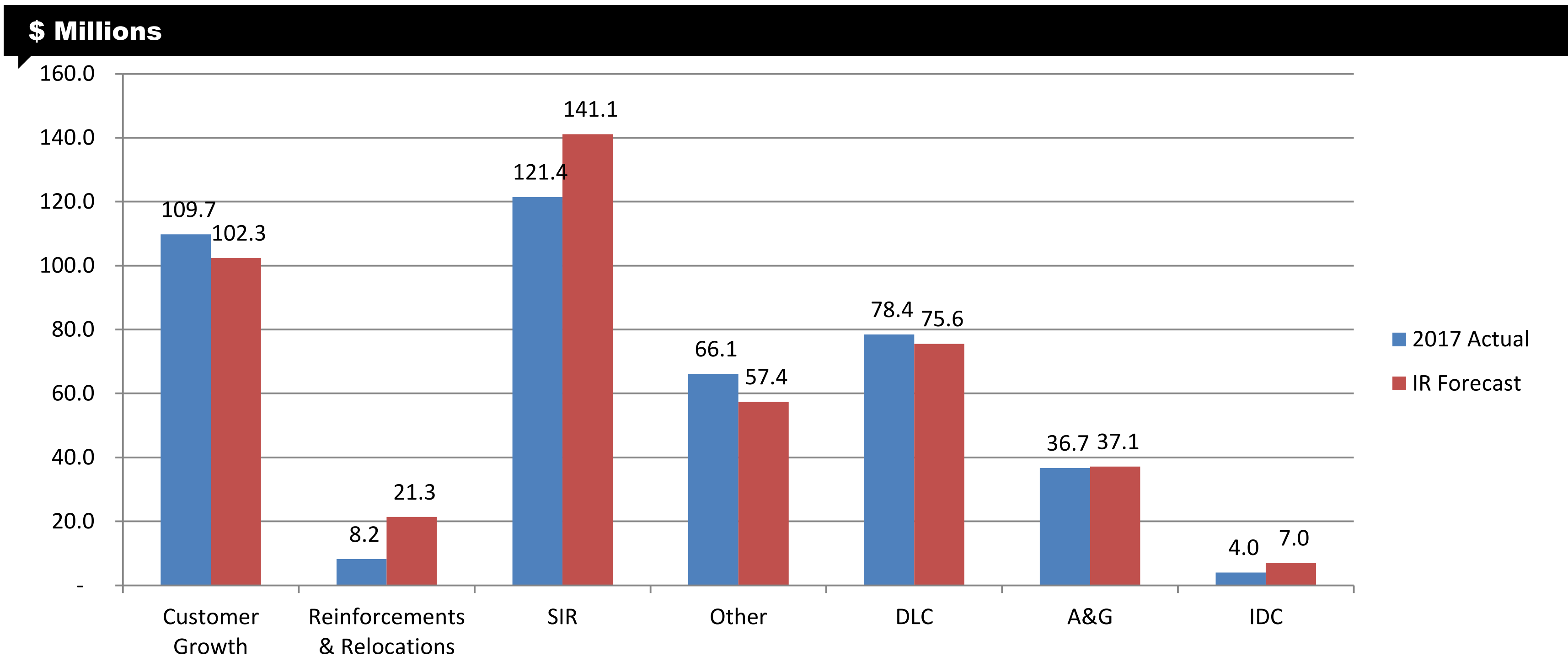
$ Millions



NOTE: GTA Actual and IR Budget includes pre-2014 spend

Total 4 year cumulative CAPEX spend greater than IR budget ($140.2) due to GTA project ($182.3) and WAMS project ($21.9), partially offset by lower Core spending ($64.0)

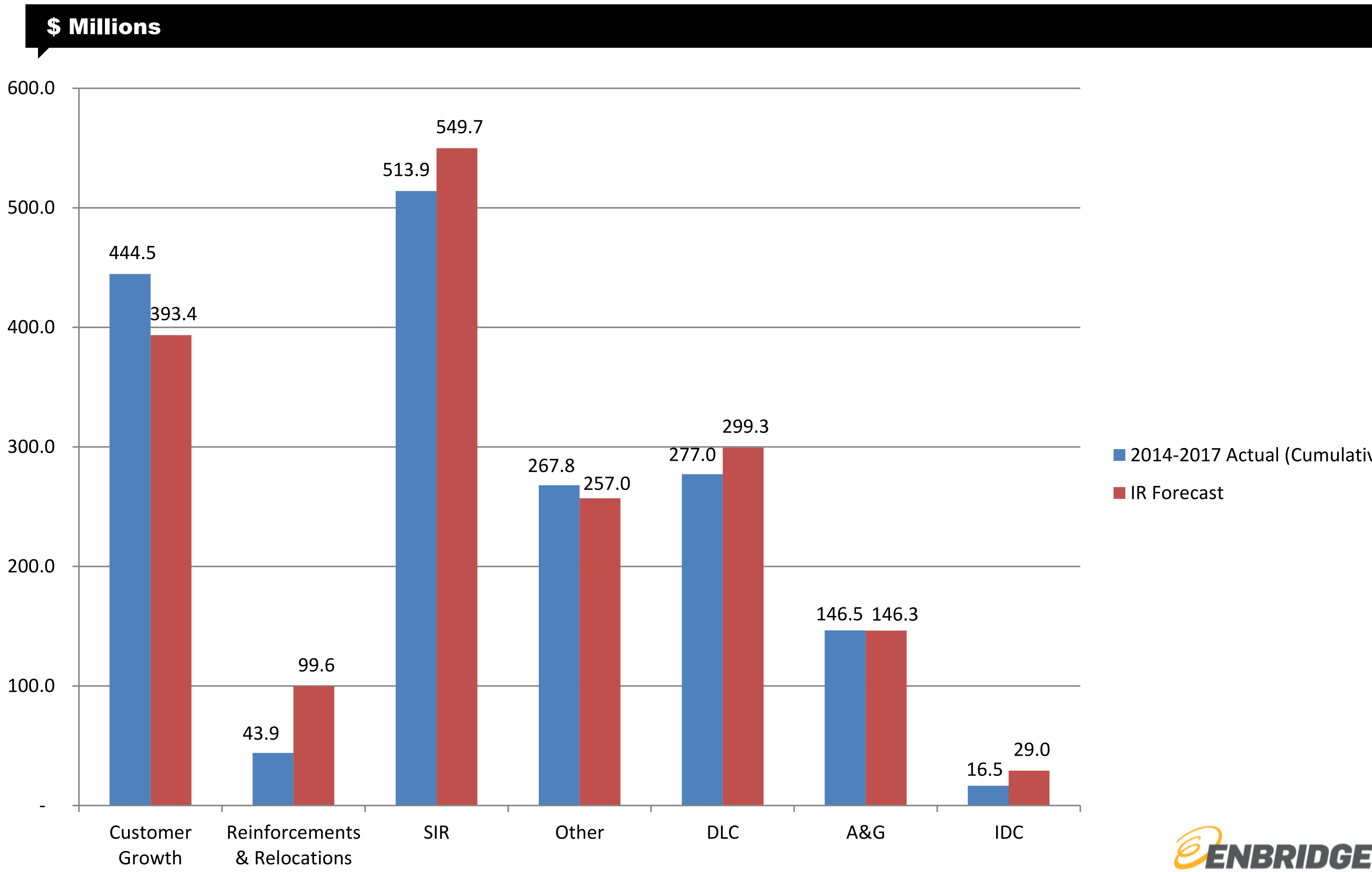
2017 What we did: Capital Management



Total Core CAPEX – Major Drivers of $17.4M Variance

- Customer Growth: $7.4M higher due to customer mix and higher unit costs
- Reinforcements: $4.1M lower due to project deferrals associated with growth
- Relocations: $9.1M lower due to incremental cost recovery with non-municipal infrastructure parties
- SIR: $19.7M lower – Refer to System Reliability section for details
- Other: $8.7M higher due to increased spend in Storage ($8.1M) on compressor equipment and foundations
- DLC: $2.8M higher due to re-allocation of labour costs as projects i.e. WAMS and Asset Management are placed into service

Capital Management: Total Core Cumulative 2014-2017



SIR, Reinforcements, Relocations & Storage - 2017

$ Thousands

Exhibit Reference	Description	2017 Act	2017 IRM	Variance
B2-5-2	Main Replacement	21,612	22,100	488
B2-5-3	Service Replacement	24,469	41,227	16,758
B2-5-4	Station Replacement	23,685	24,517	832
B2-5-5/6	Other System Integrity and Reliability	51,660	53,259	1,599
	Total System Integrity and Reliability	**121,426**	**141,103**	**19,677**
B2-3-1	Reinforcements	4,683	8,743	4,060
B2-4-1	Relocations	3,472	12,603	9,131
B2-6-1	Storage	16,975	8,910	(8,065)
	Total	**146,555**	**171,359**	**24,804**

Major Drivers of $24.8M Variance:

Service Replacement: lower by $16.8M due to deferral and reprioritization of proactive AMP program

Reinforcements: lower by $4.1M due to deferral of capacity related projects

Relocations: lower by $9.1M due to incremental cost recovery with non-municipal infrastructure parties

Storage: higher by $8.1M due to increased spend on remediation of degrading compressor foundations, and storage pipeline integrity

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Utility O&M

Sam Fallis

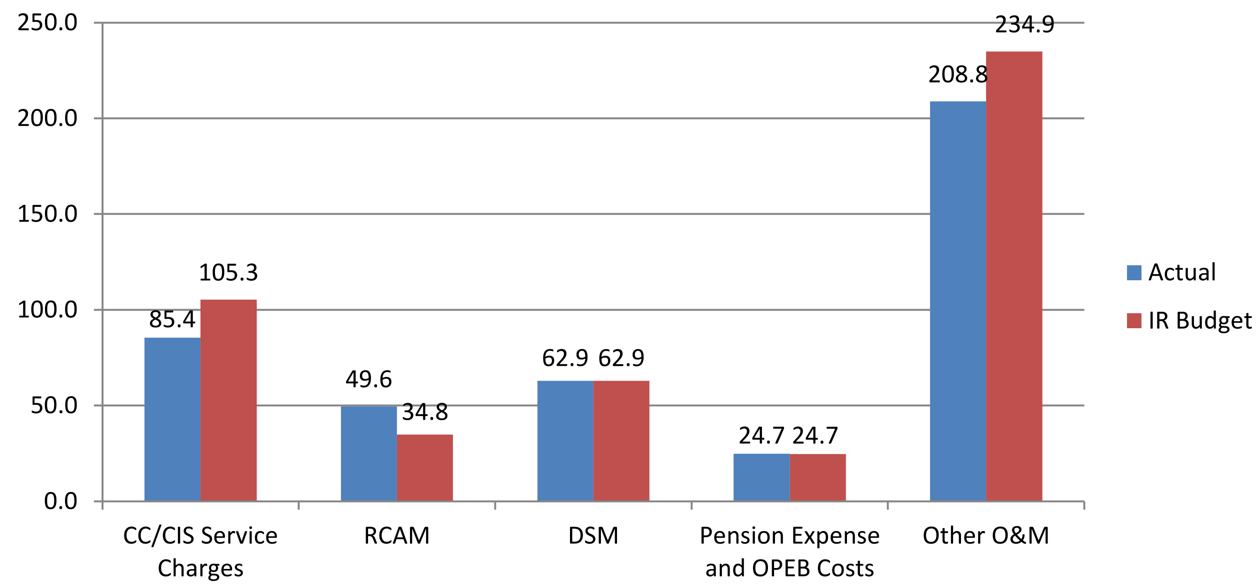
2017 Utility O&M

$ Millions

Line No.	Cost Categories ($ Millions)	2017 Actual	2017 IR Budget	Variance
1.	CC/CIS Service Charges	85.4	105.3	(19.9)
2.	RCAM	49.6	34.8	14.8
3.	DSM	62.9	62.9	0.0
4.	Pension Expense and OPEB Costs	24.7	24.7	0.0
5.	Other O&M	208.8	234.9	(26.1)
6.	**Total Net Utility O&M Expense**	**431.5**	**462.7**	**(31.2)**

2017 Utility O&M

$ Millions



Major Drivers:

1) Customer Care $19.9M lower due to reduced CIS support costs, improved collections, postage savings from higher number of customers on e-bill, and system improvements reducing manual work.

2) RCAM $14.8M higher primarily due to centralization of IT and HR services.

3) Other O&M $26.1M lower primarily due to centralization of IT and HR services (primarily shared services offset to increase in RCAM), labour reductions, and bad debt. This favourable variance is partially offset by severance costs due to workforce reductions.

2017 Year End Utility Financial results

Ryan Small

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2017 Utility Return on Equity – Actual vs. Approved

– 2017 Gross Revenue Sufficiency = $47.1M

– 2017 ESM = $23.55M

– 2017 Actual Normalized ROE Before ESM = 10.27%

– 2017 Actual Normalized ROE After ESM = 9.53%

– 2017 Board Approved ROE = 8.78%

2017 Allowed Revenue & Sufficiency – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2016-0215 Approved (Incl. CIS)	Variance
1.	Rate base	6,465.2	6,024.1	441.1
2.	Required rate of return	6.019%	6.208%	(0.189)%
3.	Cost of capital	389.1	374.0	15.1
	Cost of service			
4.	O&M (incl. CC/CIS rate smoothing adj.)	431.5	462.7	(31.2)
5.	Depreciation and amortization expense	301.3	297.7	3.6
6.	Fixed financing costs	2.8	1.9	0.9
7.	Municipal and other taxes	44.6	47.9	(3.3)
8.	Other revenues	(42.4)	(42.8)	0.4
9.	Income taxes on earnings	1.0	14.4	(13.4)
10.	Taxes on sufficiency	(12.4)	-	(12.4)
11.	Allowed revenue (excl. gas costs)	1,115.5	1,155.8	(40.3)
12.	Revenue at existing rates, net of gas costs	1,162.6	1,155.8	6.8
13.	Gross revenue sufficiency	47.1	-	47.1

* 2017 earnings sharing payable to ratepayers = $23.55M

2017 Utility Rate Base – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2016-0215 Approved (Incl. CIS)	Variance
1.	Net property, plant, & equip.	6,102.3	5,695.9	406.4
2.	Gas in storage	372.0	356.6	15.4
3.	Other working capital items	(9.1)	(28.4)	19.3
4.	Utility Rate Base	6,465.2	6,024.1	441.1

- PP&E – higher predominantly due to variances from prior years reflected in opening 2017 balances, including GTA and WAMs project variances.
- Gas in storage – higher primarily due to higher QRAM approved PGVA reference prices.
- Other working capital items – lower customer security deposits

2017 Utility Capital Structure – Actual vs. Approved

2017 ACTUAL UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,677.3	56.88	4.86	2.764	178.7
2.	Short term debt	360.4	5.57	1.05	0.058	3.8
3.	Preference shares	100.0	1.55	2.32	0.036	2.3
4.	Common equity	2,327.5	36.00	8.78	3.161	204.3
5.		6,465.2	100.00		6.019	389.1

EB-2016-0215 2017 APPROVED UTILITY CAPITAL STRUCTURE

Line No.		Principal Incl. CC/CIS	Component	Indicated Cost Rate	Return Component	Return
		($Millions)	%	%	%	($Millions)
1.	Long term debt	3,752.2	62.29	4.83	3.010	181.3
2.	Short term debt	3.2	0.05	1.23	0.001	0.0
3.	Preference shares	100.0	1.66	2.24	0.037	2.2
4.	Common equity	2,168.7	36.00	8.78	3.160	190.4
5.		6,024.1	100.00		6.208	374.0

2017 Utility Income – Actual vs. Approved

Line No.	($Millions)	Actual (Incl. CIS)	EB-2016-0215 Approved (Incl. CIS)	Variance
1.	Distribution margin (dist. rev. - gas costs)	1,162.6	1,155.8	6.8
2.	Other revenues	42.4	42.8	(0.4)
3.		1,205.0	1,198.6	6.4
4.	O&M (incl. CC/CIS rate smoothing adj.)	431.5	462.7	(31.2)
5.	Depreciation and amortization expense	301.3	297.7	3.6
6.	Fixed financing costs	2.8	1.9	0.9
7.	Municipal and other taxes	44.6	47.9	(3.3)
8.	Total costs and expenses	780.2	810.2	(30.0)
9.	Utility income before income taxes	424.8	388.4	36.4
10.	Income tax expense	1.0	14.4	(13.4)
11.	Utility net income	423.8	374.0	49.8

- Margin – Higher gas in storage carrying charges reflected in rates (QRAM updates), and lower S&T fuel charges.
- O&M – Lower compensation costs (staff reductions), lower CC & CIS costs, and lower bad debt.
- Depreciation – Impact of higher gross PP&E balances.
- Fixed financing costs – Impact of increased credit facility.
- Municipal taxes – Lower than forecast municipal tax rate increases.
- Income tax expense – Higher than forecast net tax deductions (incl. CCA on WAMs and the GTA project).

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Utility Return on Equity – Actual vs. Approved

	2017	2016	2015	2014
- Gross Revenue Sufficiency	$47.1M	$6.8M	$12.9M	$25.3M
- ESM Amount	$23.55M	$3.4M	$6.45M	$12.65M
- Actual Normalized ROE Before ESM	10.27%	9.42%	9.82%	10.46%
- Actual Normalized ROE After ESM	9.53%	9.31%	9.56%	9.91%
- Board Approved ROE	8.78%	9.19%	9.30%	9.36%

Productivity

Margarita Suarez

Overview of Productivity Reporting

- 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
  - Enbridge's required operational and customer service levels must not be compromised
  - All productivity actions matter. No materiality threshold was defined
- This resulted in over 180 reported (sustained and new) initiatives, which underpin the remainder of the presentation

2017 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 Savings	(26.2)	(28.7)	(27.1)	(28.4)	(32.3)	(142.7)
Less: Variable Costs	(25.1)	(63.0)	(75.9)	(50.0)	(50.0)	(264.0)
Less: OEB Adjustment	-	-	-	(6.8)	(13.0)	(19.8)
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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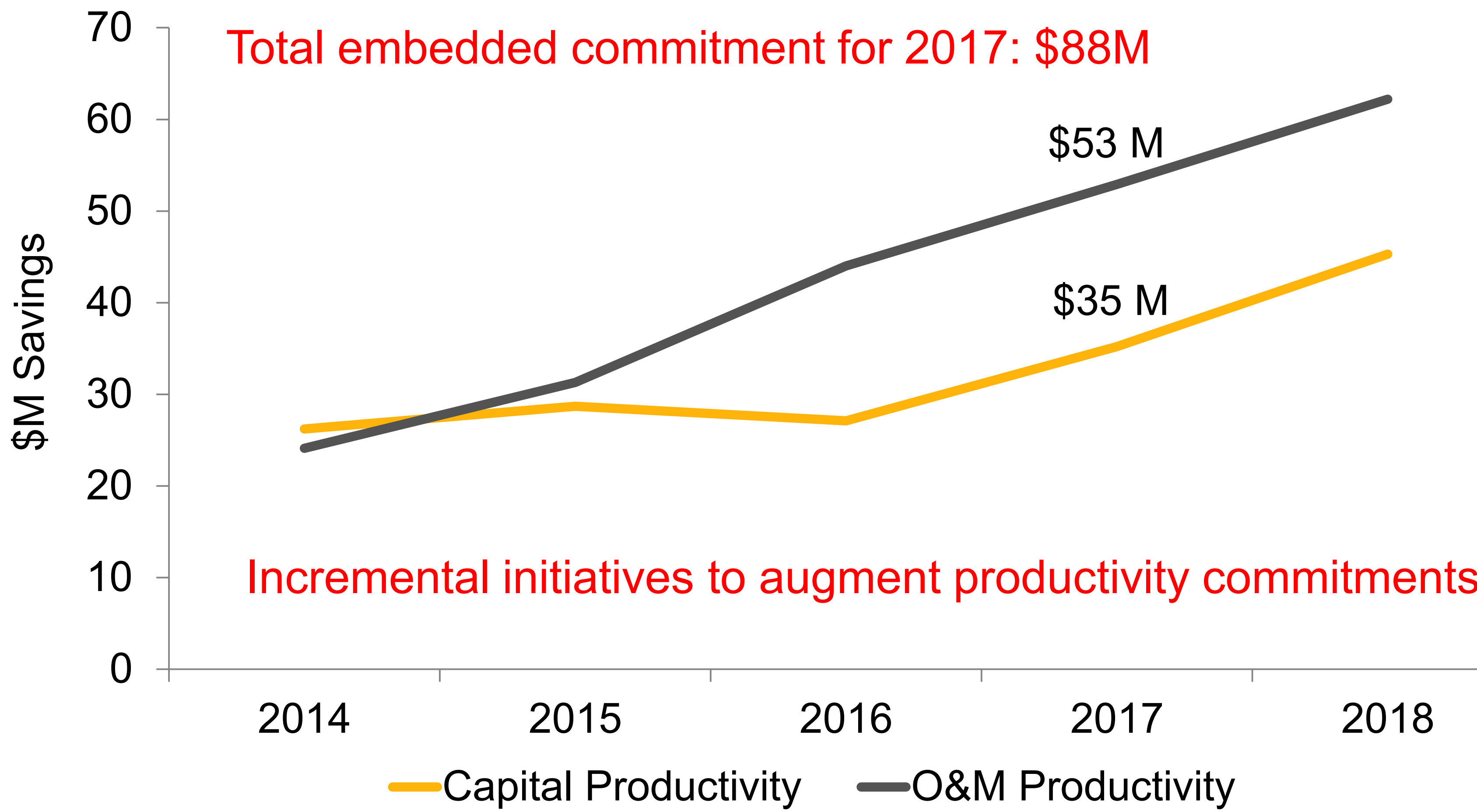
2017 O&M and Capital Productivity Commitments



Embedded Commitments -- O&M and Capital

O&M and Capital Embedded Productivity Results

2017 Embedded O&M and Capital Reductions		Embedded Commitment ($M)	Actual ($M)
1	O&M: Merit Increase	(3.5)	(0.5)
2	O&M: Employee Benefit	(3.3)	(5.2)
3	O&M: Incremental cost to service new customers	(1.8)	(0.5)
4	O&M: Incremental safety and Integrity work	(9.5)	(1.7)
5	O&M: External contractor rate increases	(2.0)	(0.4)
6	O&M: Increased volume of locates-compliance with Bill 8	(4.5)	(7.7)
7	O&M: FTEs	(8.8)	(16.1)
8	O&M: Bad Debt expenses	(5.9)	(10.0)
9	Total O&M Productivity Guarantee	(39.3)	(42.2)
10	Capital: Customer Attachments	(24.6)	(17.2)
11	Capital: Departmental Labour	(4.2)	(1.4)
12	Total Capital Productivity Guarantee	(28.8)	(18.5)
13	Total Embedded O&M & Capital Reductions	(68.1)	(60.7)

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Incremental Initiatives - O&M

2017 Incremental O&M Productivity Initiatives				
Amounts reported in millions	**2016 Savings on Sustained Initiatives**	**2017 Savings on Sustained Initiatives**	**2017 Savings on New Initiatives**	**Total 2017**
Labour Optimization	(2.0)	(2.3)	(0.0)	(2.3)
Process Optimization	(5.9)	(8.1)	(0.03)	(8.2)
Materials/Space/Equipment Rationalization	(4.1)	(2.5)	(0.7)	(3.3)
Policy Change and Improvements	(0.9)	(0.9)	-	(0.9)
Total Reductions from Incremental O&M Initiatives	(12.9)	(13.9)	(0.8)	(14.6)

Incremental Initiatives - Capital

2017 Incremental Capital Productivity Initiatives				
Amounts reported in millions	2016 Savings on Sustained Initiatives	2017 Savings on Sustained Initiatives	2017 Savings on New Initiatives	Total 2017
Labour Optimization	(1.3)	(0.7)	-	(0.7)
Process Optimization	(2.0)	(2.0)	(0.4)	(2.5)
Materials/Space/Equipment Rationalization	(1.3)	(2.0)	-	(2.0)
Policy Change and Improvements	(0.3)	(0.6)	-	(0.6)
Total Reductions Available for Capital Reallocation	(4.9)	(5.4)	(0.4)	(5.8)

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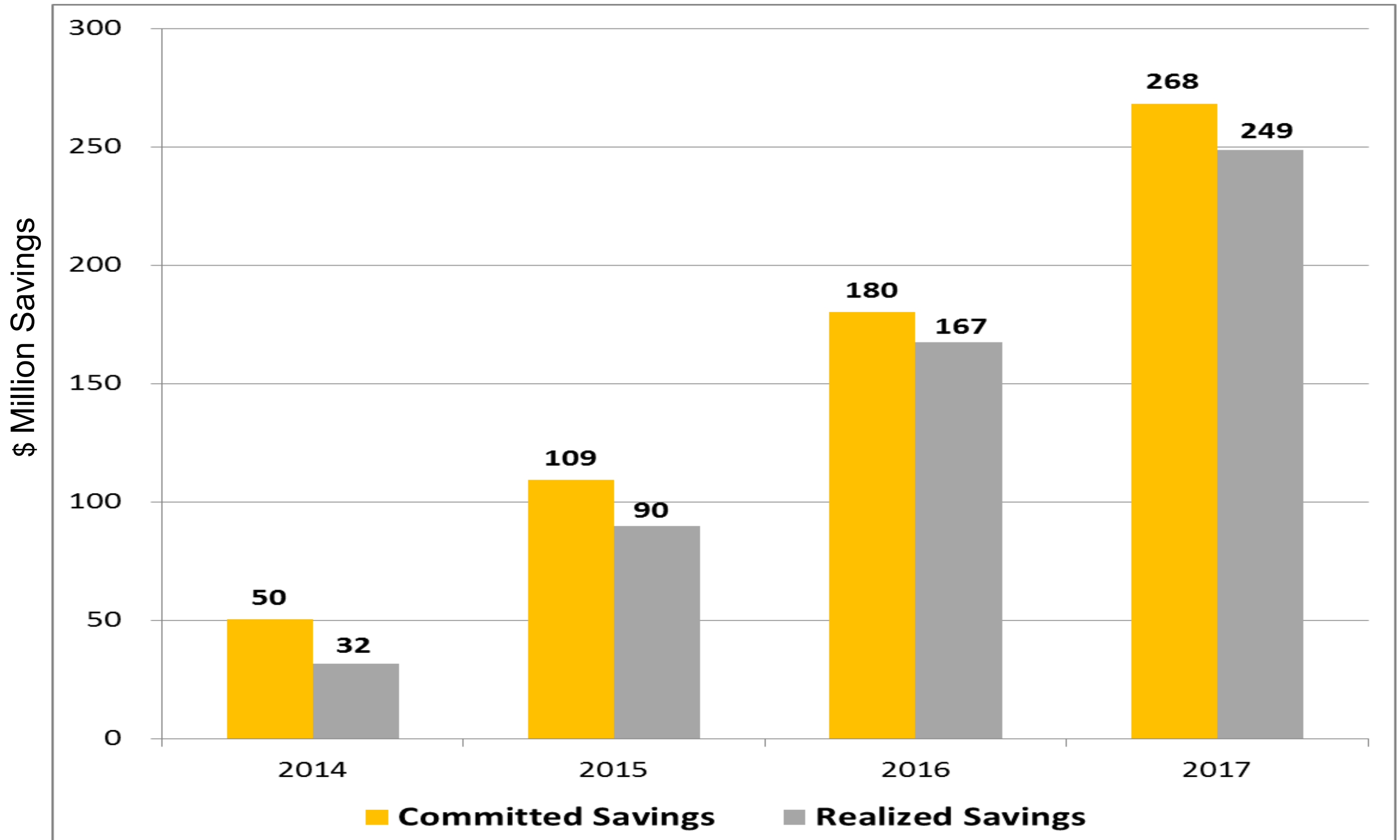
Overall 2017 Productivity Results

	2017					
	O&M ($M)		Capital ($M)		Total ($M)	
	Commitment	Actual	Commitment	Actual	Commitment	Actual
Embedded	(39.3)	(42.2)	(28.8)	(18.5)	(68.1)	(60.7)
Incremental		(14.6)		(5.8)		(20.4)
OEB Adjustment	(13.6)		(6.4)		(20.0)	
2017 Total Savings	(52.9)	(56.8)	(35.2)	(24.3)	(88.1)	(81.2)

Cumulative Productivity Savings



Performance Measures

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

Customer Relationship Performance Measure Results

All Customer Relationship metrics are achieving strong performance

Customer Relationship Performance	OEB Target	2013	2014	2015	2016	2017	Trending
1. Overall Customer Satisfaction Index	NA	78%	77%	79%	79%	79%	↑
2. Call Answering Service Level (SQR)	75%	75.9%	79%	79.7%	82.4%	82.5%	↑
3. Percentage of Emergency Calls Responded to within One Hour (SQR)	90%	96.1%	96.9%	96.7%	95.2%	96.8%	↔
4. Appointments Met within the Designated Time Period (SQR)	85%	94.2%	95.1%	95.2%	95.3%	94.8%	↔
5. Time to Reschedule a Missed Appointments (SQR)	100%	95.0%	95.5%	94.8%	95.0%	96.8%	↑
6. Number of Days to Reconnect a Customer (SQR)	85%	92.6%	94.0%	94.6%	94.8%	96.2%	↑
7. Number of Calls Abandon Rate (SQR)	10%	2.8%	1.9%	2.3%	1.8%	1.8%	↑
8. Meter Reading Performance (SQR)	0.5%	0.50%	0.69%	0.51%	0.40%	0.50%	↔
9. Number of Days to provide a Written Response (SQR)	80%	94.5%	93.3%	100.0%	95.5%	100.0%	↑

↑ – Improving
↔ – Stable
↓ – Decreasing

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Operational Performance Measure Results

All Operational Performance metrics are achieving strong performance

Operational Performance	2013	2014	2015	2016	2017	Trending
1. Employees Health and Safety: Total Reportable Injury Frequency Rate	2.01	2.00	1.06	0.93	1.04	⟷
2. Damage Prevention: Number of Excavation Damages per 1000 locates	2.84	2.49	2.43	2.17	1.81	↑
3. Leak Management: Service leaks Repaired per Mile of service	0.09	0.06	0.06	0.06	0.08	⟷
4. Leak Management: Total Number of Grade 1 (A) leaks repaired during the year	1280	661	905	991	1216	⟷
5. Operational Effectiveness: All Outages per 1000 Customers	6.09	5.31	4.84	4.60	4.76	⟷

↑ – Improving
⟷ – Stable
↓ – Decreasing

Gas Supply Plan

Andrew Welburn

ENBRIDGE®

Agenda

1. A Glance Back at the First Quarter of 2018
2. Current Renewable Natural Gas Procurement
3. TransCanada Mainline 2018-2020 Toll Review
4. Looking Forward to New Transportation Capacity

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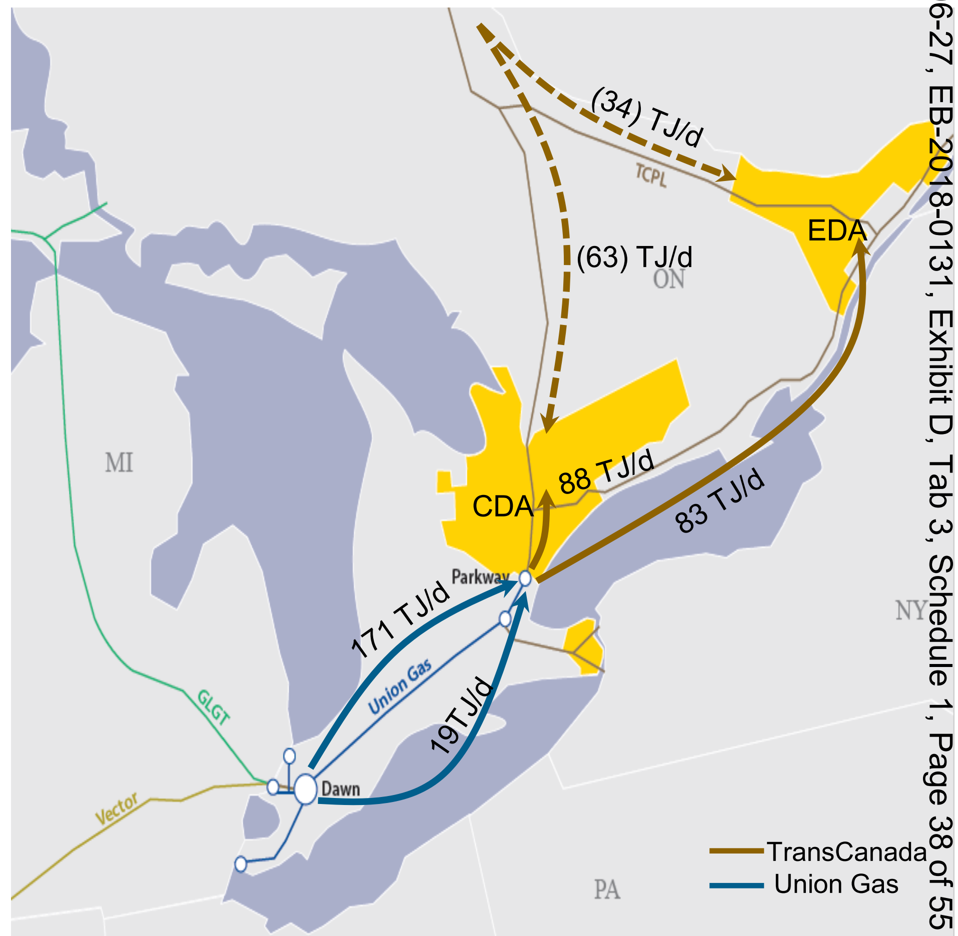
A Glance Back at the First Quarter of 2018

2018 Gas Supply Portfolio Changes

The conversion of 97TJ per day reduces long-haul transportation to Mainline Settlement Agreement minimum level of 265 TJ per day

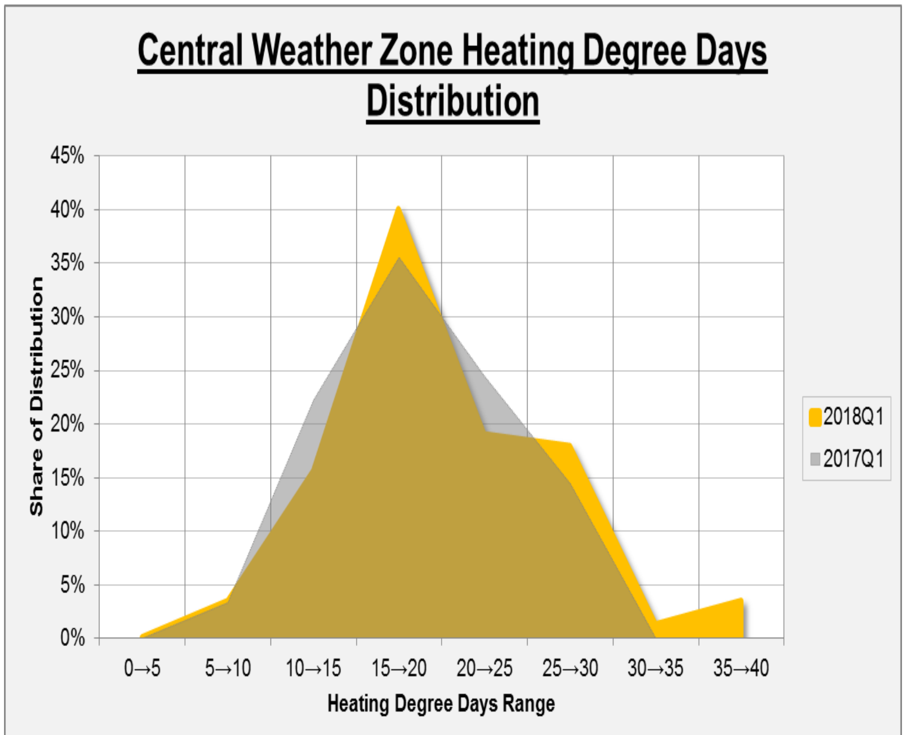
- Union Gas and TransCanada new capacity in-service November 1, 2017
- Dawn Transportation Service (DTS) implemented November 1, 2017
- Incremental 2 PJ of third party storage contracted April 1, 2018



2018 Winter Weather

Significant volatility with the first quarter of 2018

- January was the 3rd-most volatile on record
- February was 40% colder in 1st half compared to 2nd half of the month
- March was the 2nd least volatile month on record



2018 Q1 Heating Degree Days
Budget vs Actual, by Weather Zone

	Central	Eastern	Niagara
Actual	1,825	2,089	1,722
Budget	1,832	2,183	1,741
Variance	-0.3%	-4.3%	-1.1%

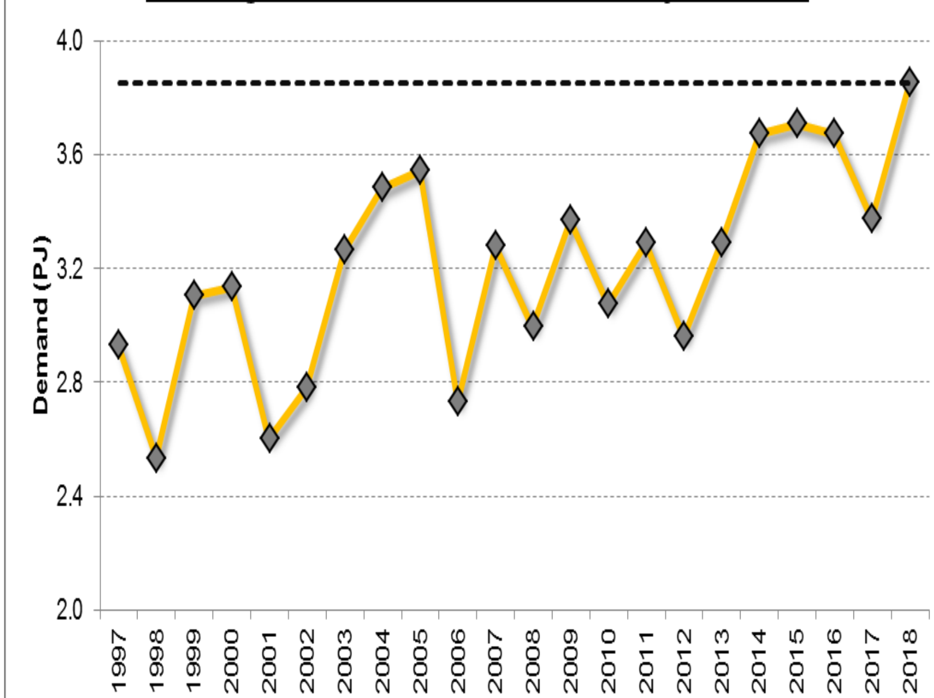
2018 Winter Peak Demand

Peak day demand continues to trend upward

- 2018 Peak Day occurred on Friday, January 5th
  - Approximately 3.9 PJs (37.4 HDDs in Central weather zone)
  - Highest peak day on record

- 2017 Peak Day occurred on Sunday, December 31st
  - Approximately 3.4 PJs (35.5 HDDs in Central weather zone)
  - 1st time since 1998 that peak day occurred in December and not Q1
  - April 2018 was 13.3 PJ above budget

Enbridge Gas Distribution: Peak Day Demand



2018 Winter Prices

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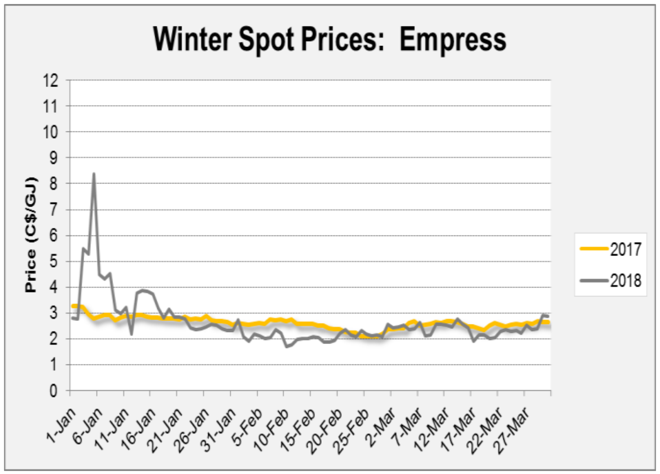
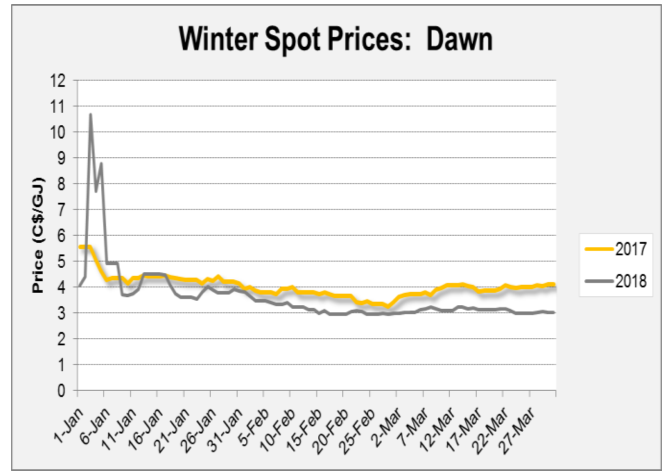
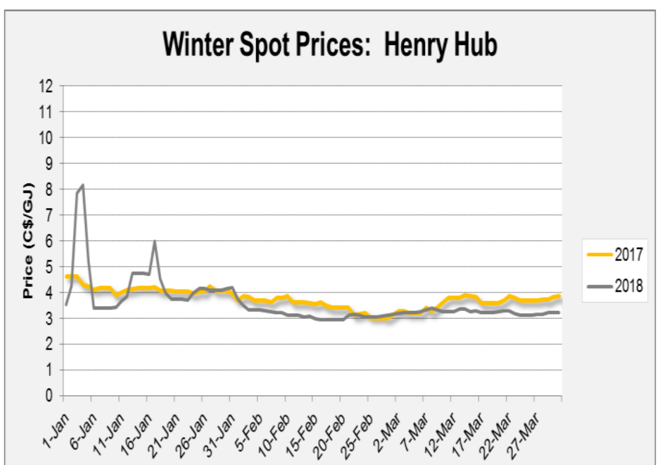
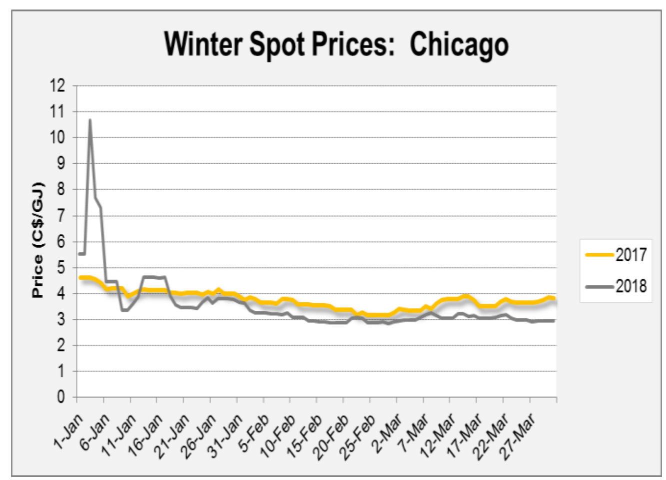
Life Takes Energy

Markets saw prices spike at the start of 2018, but uneventful spot prices for rest of the quarter









Current Renewable Natural Gas Procurement

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Setting the Stage for Renewable Natural Gas

Enbridge Gas Distribution is working with the Ontario Government to support Renewable Natural Gas (RNG) development

- Climate Change Mitigation and Low-carbon Economy Act, 2016 (Climate Change Act)
- Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap & Trade Activities issued September 2016
- Collection of emission compliance costs included in natural gas bills effective January 1, 2017
- Ontario Government has communicated plans to invest $100 million to develop RNG in Ontario
- EGD initiated an RNG Request for Proposals (RFP) in February but process is currently on hold until after the Ontario election

Gas Supply Planning Principles

These principles are central to gas supply procurement decisions

Diversity
- Inclusion of RNG in gas supply portfolio
- Potential for procurement from multiple biogas sources

Reliability
- Biogas/RNG production
- Ability to procure supply in-franchise

Flexibility
- Contract term duration

Prudent Cost
- Government funding
- Cost neutral for customers

Application of Ontario Government Funding

ENBRIDGE Life Takes Energy

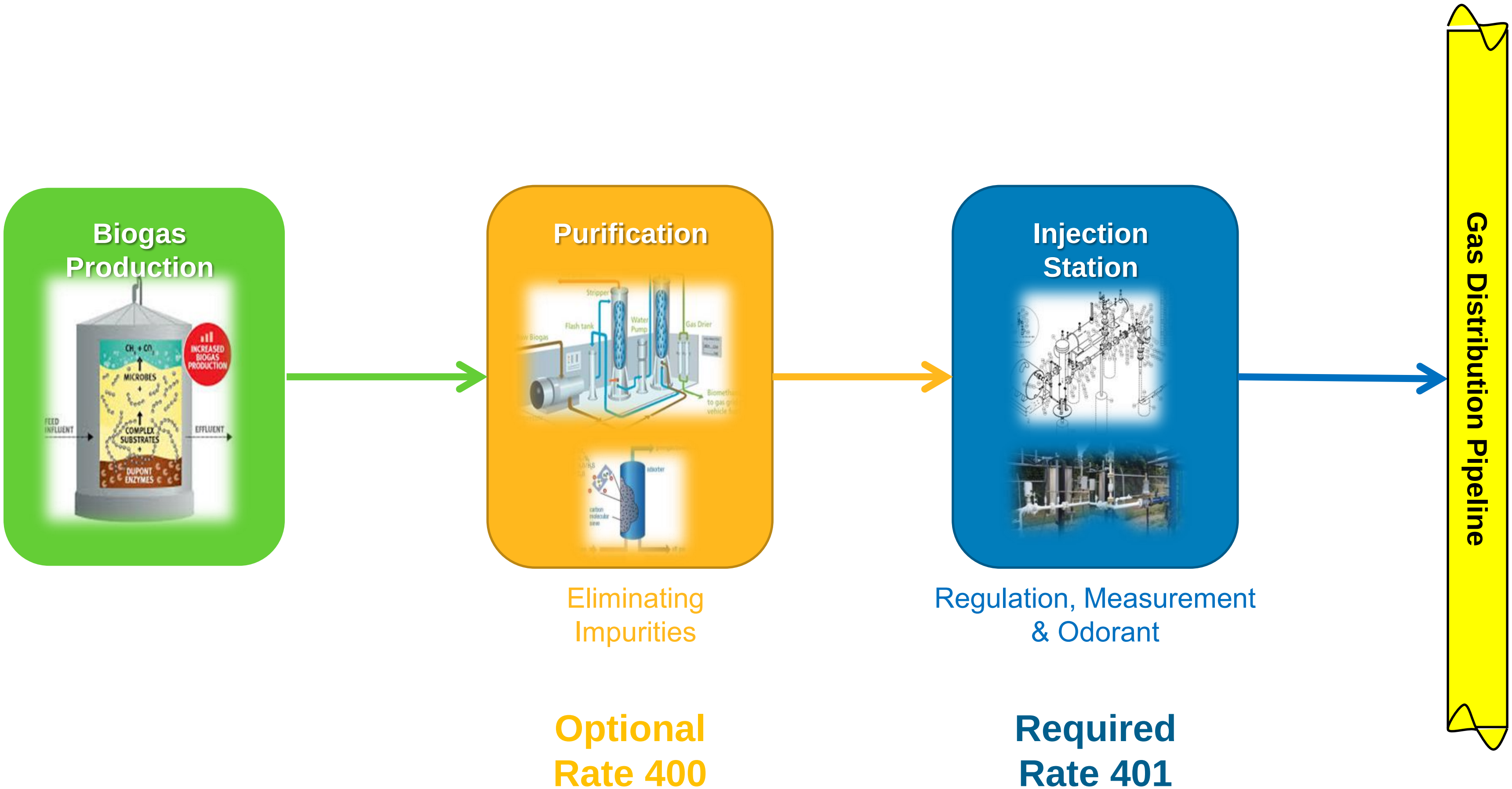
Ontario Government funding will be used to manage Ratepayer impact under the current RFP process

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 9	Year 9	Year 10
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(a)	Forecast Cost of Traditional Gas Supplies ($/GJ)[1]	$ 3.69	$ 3.45	$ 3.42	$ 3.43	$ 3.46	$ 3.59	$ 3.65	$ 3.73	$ 3.82	$ 3.[illegible]6
(b)	Forecast Cost of Carbon: Mid-Range LTCPF ($/GJ)[2]	$ 0.85	$ 0.90	$ 0.90	$ 0.95	$ 1.00	$ 1.05	$ 1.56	$ 1.81	$ 2.16	$ 2.[illegible]1
(c)	Required Provincial Subsidy ($/GJ)[3] (c) = (d) - (a) - (b)	$ 11.46	$ 11.65	$ 11.68	$ 11.61	$ 11.53	$ 11.35	$ 10.79	$ 10.46	$ 10.02	$ 9.[illegible]3
(d)	Assumed Cost of RNG ($ / GJ)	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00	$ 16.00

Source: 2018 Cap and Trade Compliance Plan Application, EB-2017-0224, Exhibit C, Tab 5, Schedule 2, Table 2

Connecting RNG to the Market

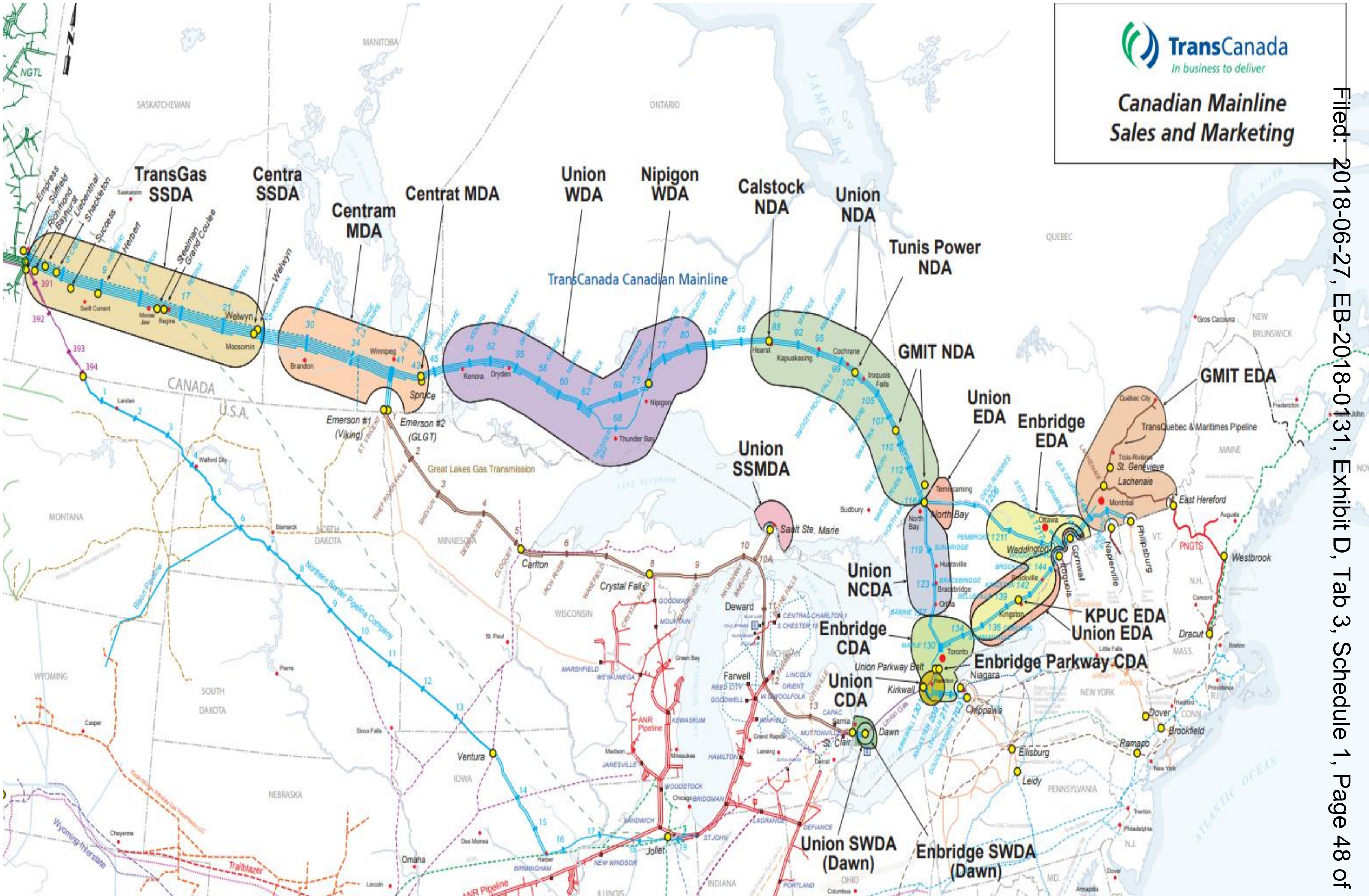
Enbridge Gas Distribution is developing services to connect RNG to the market



The RFP Process

The final stage of the RFP process is on hold pending confirmation of the Ontario Government investment

February 23	• Issue RFP
March 1	• Information Webinar
March 7	• Producers Submit Preliminary RFP Responses
March 12	• Utilities Communicate Initial Screening Results
March 29	• Producers Receive connection and service estimate
April 12	• Producers Submit Final RFP Response
TBD	• **Utilities Award RNG Contracts**



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TransCanada Mainline 2018-2020 Toll Review

TransCanada Mainline 2018-2020 Toll Review

Enbridge Gas Distribution continues to work with TransCanada to address complex tolling issues

- Current tolling methodology includes fixed tolls for 2015 – 2020 that would be reviewed for the 2018-2020 period
- Agreement reached between Enbridge Gas Distribution, Union Gas and Énergir, and TransCanada on proposed 2018-2020 tolls
- Application filed by TransCanada in December 2017

Haul Type	Tolls in Relation to RH-003-2011	Toll Change from Current Level
Eastern Triangle Short-Haul	135%	-13%
Eastern Triangle Long-Haul	111%	-4%
Other	106%	-2%

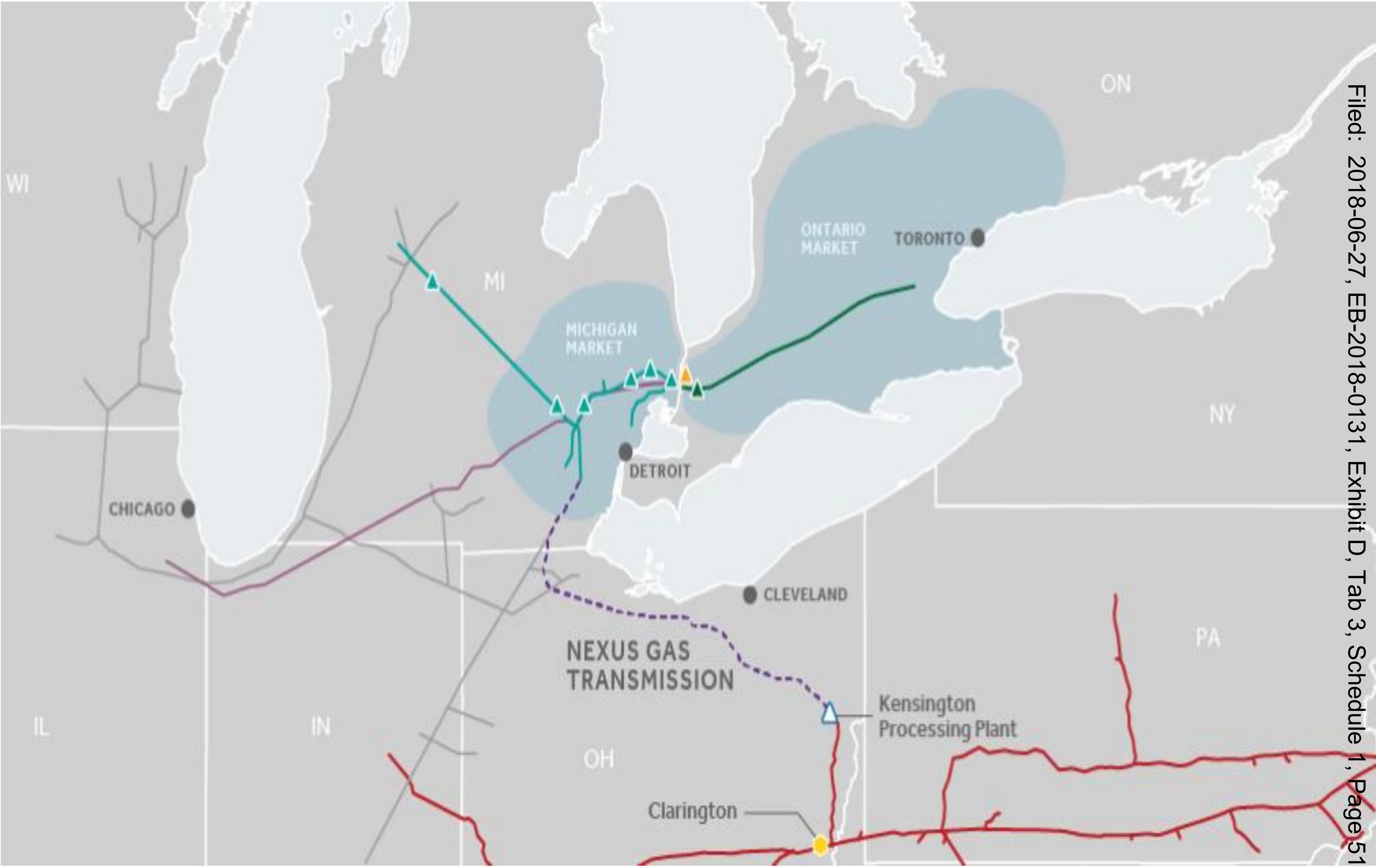
- Application under review by the National Energy Board (NEB) and scheduled to conclude in September 2018 with a decision to follow
- Interim tolls consistent with proposed 2018-2020 toll

Toll Impact Summary

Proposed tolls for 2018-2020 would result in a $30 million annual reduction in TransCanada toll costs

Receipt	Delivery	Volume (GJ/d)	2015-2017 Toll ($/GJ)	Proposed Toll ($/GJ)	2015-2017 Annual Cost ($M)	Proposed Annual Cost ($M)	Proposed Cost Variance ($M)
Empress	Enbridge EDA	163,044	1.8817	1.7988	112.0	107.0	(4.9)
Empress	Enbridge CDA	75,000	1.8270	1.7465	50.0	47.8	(2.2)
Empress	Iroquois	26,956	1.8939	1.8105	18.6	17.8	(0.8)
Dawn	Enbridge EDA	114,000	0.6789	0.5903	28.2	24.6	(3.7)
Dawn	Enbridge CDA	149,818	0.3711	0.3227	20.3	17.6	(2.6)
Dawn	Iroquois	40,000	0.6526	0.5674	9.5	8.3	(1.2)
Parkway	Enbridge EDA	333,725	0.4986	0.4335	60.7	52.8	(7.9)
Parkway	Enbridge CDA	372,416	0.1992	0.1732	27.1	23.5	(3.5)
Parkway	Vic Sq #2	85,000	0.2018	0.1755	6.3	5.4	(0.8)
Niagara	Enbridge Parkway CDA	76,559	0.2384	0.2073	6.7	5.8	(0.8)
Chippawa	Enbridge Parkway CDA	123,441	0.2403	0.2089	10.8	9.4	(1.4)
Total					**350.3**	**320.2**	**(30.1)**

Tolls are for firm transportation only and exclude fuel and abandonment surcharge costs.



Looking Forward to New Transportation Capacity

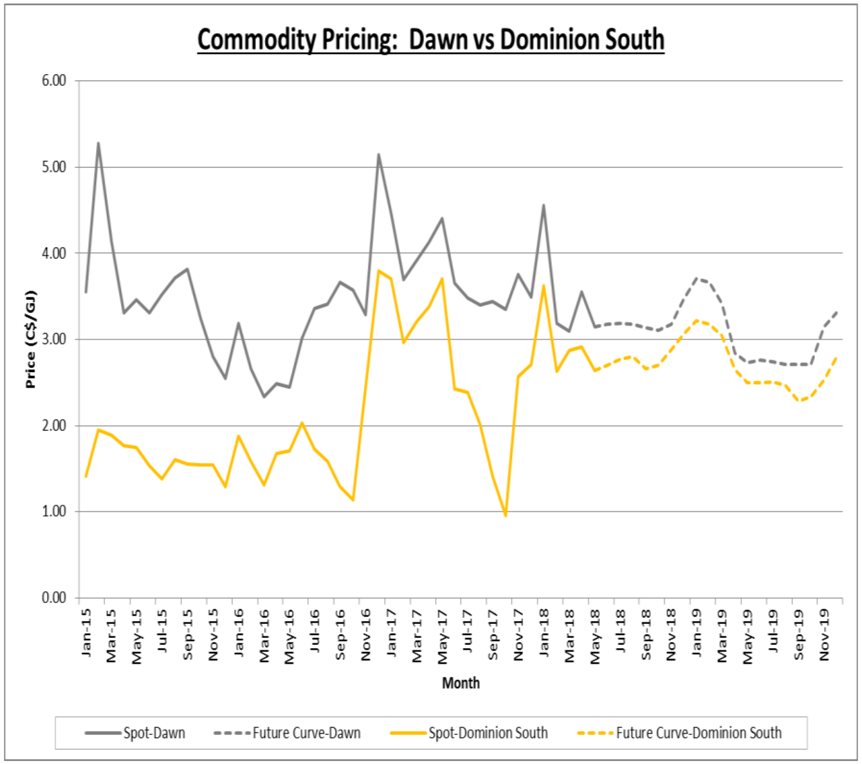
NEXUS Transportation

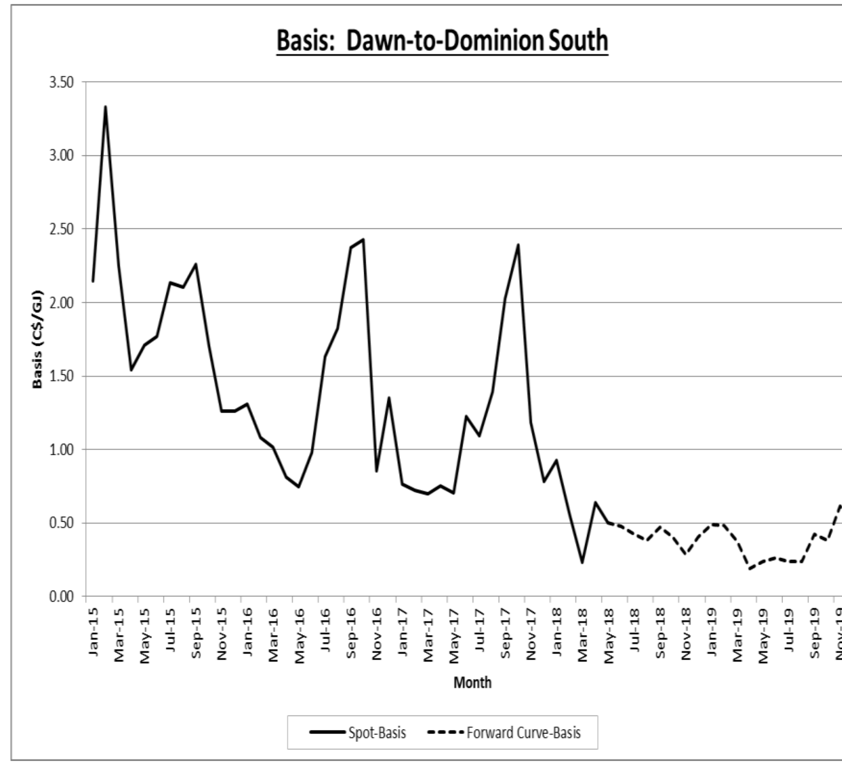
Construction is underway and NEXUS is anticipated to be in service for the late third quarter of 2018

- Federal Energy Regulatory Commission (“FERC”) approved the construction and operation of the NEXUS Project in August 2017
- Construction of the pipeline, compressor stations, and metering and regulation sites are underway
- Supply arrangements are under negotiation for both Clarington (Teal) and Kensington Processing Plant
- Planned in-service date for contracted 110,000 Dth per day of capacity from Kensington to Milford Junction is late third quarter of 2018

NEXUS Supply

North America's natural gas market continues to evolve as supply basins connect to markets

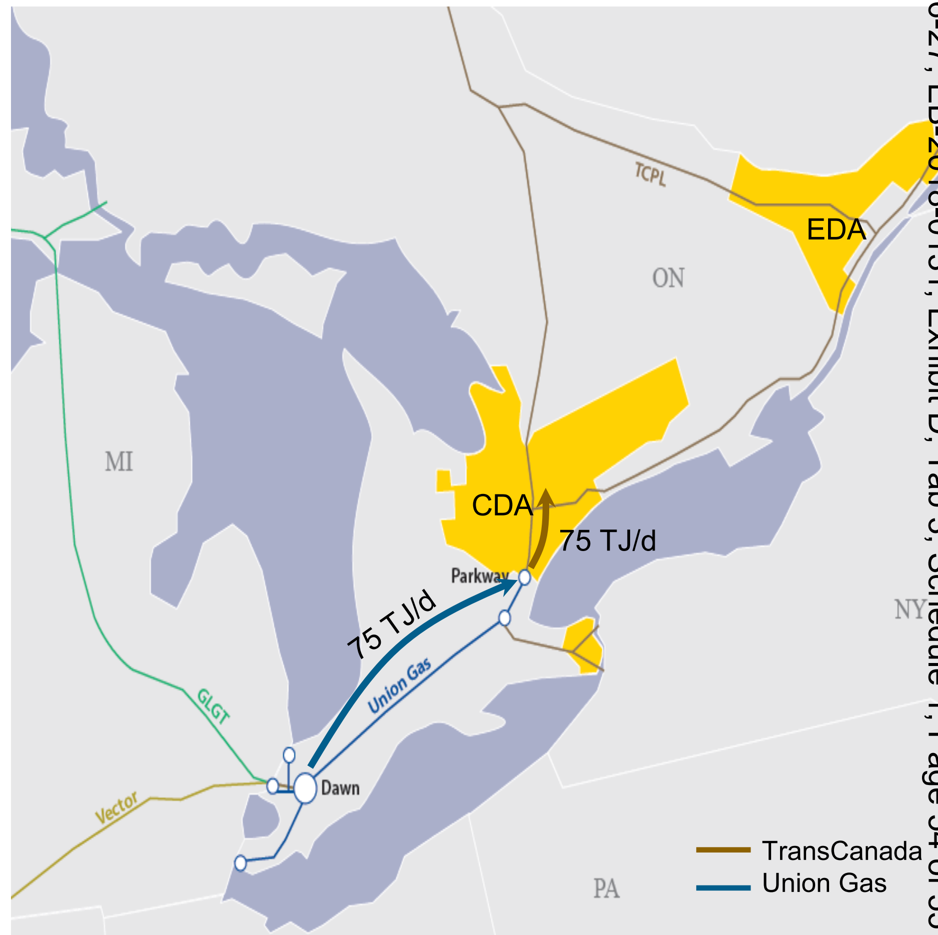




Union Gas and TransCanada Transportation

Union Gas and TransCanada transportation capacity work in tandem to access supply at the Dawn Hub

- Planned in-service date of November 1, 2019
- Union Gas new facilities approved by the OEB and anticipated to be constructed on schedule
- TransCanada transportation new facilities approved by the NEB but could face delays
  - Intervenor leave to appeal application before the Federal Court of Appeal
  - Intervenor application to stay facility construction before the NEB



Closing Remarks

Kevin Culbert

2017 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.	187,866	224,409	83.7%
Feb.	91,821	121,749	75.4%
Mar.	184,048	229,715	80.1%
Apr.	131,591	153,382	85.8%
May	184,102	228,026	80.7%
Jun.	181,867	214,400	84.8%
Jul.	163,992	202,685	80.9%
Aug.	167,777	207,847	80.7%
Sept.	163,282	197,829	82.5%
Oct.	173,374	220,224	78.7%
Nov.	179,846	209,474	85.9%
Dec.	152,216	168,399	90.4%
TOTAL	1,961,782	2,378,139	82.5%

Witnesses: D. Brault
D. McIlwraith

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

Month	Number of Calls Abandoned While Waiting for a Live Agent (1)	Total Number of Calls Requesting to Speak to a Live Agent (2)	Abandon Rate (%) (3=1/2*100)
Jan.	2,438	134,428	1.8%
Feb.	2,721	94,047	2.9%
Mar.	3,985	142,624	2.8%
Apr.	1,303	110,340	1.2%
May	2,529	143,926	1.8%
Jun.	2,435	134,937	1.8%
Jul.	2,031	125,019	1.6%
Aug.	2,528	130,498	1.9%
Sept.	1,732	124,352	1.4%
Oct.	2,836	140,519	2.0%
Nov.	1,670	130,805	1.3%
Dec.	948	99,667	1.0%
TOTAL	27,156	1,511,162	1.8%

Witnesses: D. Brault
D. McIlwraith

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	2,254,854	45,762	12,482	
February	2,104,843	32,242	11,564	
March	2,298,367	36,438	15,897	
April	2,061,058	30,283	14,232	
May	2,311,788	33,924	17,474	
June	2,263,311	35,,547	21,023	
July	2,042,526	54,766	17,770	
August	2,351,651	71,059	13,833	
September	2,252,165	67,464	11,030	
October	2,214,981	59,838	20,033	
November	2,290,402	15,870	8,390	
December	2,135,764	11,137	5,031	
Total	26,581,710	494,330	168,759	

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

Witnesses: D. Brault
D. McIlwraith

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	10,983	2,163,183	0.5%
Feb	15,447	2,165,920	0.7%
Mar	15,385	2,168,645	0.7%
Apr	9,339	2,170,997	0.4%
May	7,430	2,173,464	0.3%
Jun	7,026	2,175,928	0.3%
Jul	7,411	2,178,655	0.3%
Aug	8,560	2,181,136	0.4%
Sep	9,463	2,183,856	0.4%
Oct	9,738	2,186,721	0.5%
Nov	10,321	2,189,705	0.5%
Dec	13,470	2,192,213	0.6%
Total	124,573	26,130,423	0.5%

Witnesses: D. Brault
D. McIlwraith

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	2,698	2,856	94.5%
Feb	2,279	2,420	94.2%
Mar	3,016	3,192	94.5%
Apr	2,813	2,994	94.0%
May	3,396	3,561	95.4%
Jun	3,558	3,732	95.3%
Jul	3,324	3,480	95.5%
Aug	3,696	3,901	94.7%
Sep	3,722	3,942	94.4%
Oct	5,195	5,551	93.6%
Nov	5,051	5,445	92.8%
Dec	3,410	3,640	93.7%
Total	42,158	44,714	94.3%

Witnesses: D. Brault
D. McIlwraith

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	134	130	4 calls missed: 4 calls arrived later than 2 hours	97%
Feb	114	112	2 calls missed: 2 calls arrived later than 2 hours	98.2%
Mar	156	151	5 calls missed; 5 calls arrived later than 2 hours	96.8%
Apr	151	148	3 calls missed; 1 calls arrived later than 2 hours, 2 rescheduled after 2 hour limit without notifying customer	98%

Witnesses: D. Brault
D. McIlwraith

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	141	133	8 calls missed: 5 calls arrived later than 2 hours, 3 rescheduled after 2 hour limit without notifying customer	94.3%
Jun	140	131	9 calls missed: 9 calls arrived later than 2 hours	93.6%
Jul	137	131	6 calls missed: 5 calls arrived later than 2 hours, 1 rescheduled after 2 hour limit without notifying customer	95.6%
Aug	182	177	5 calls missed: 3 calls arrived later than 2 hours, 2 rescheduled after 2 hour limit without notifying customer	97.3%
Sep	192	187	5 calls missed: 5 calls arrived later than 2 hours	97.4%
Oct	325	318	7 calls missed: 5 calls arrived later than 2 hours, 2 rescheduled after 2 hour limit without notifying customer	97.8%
Nov	357	348	9 calls missed: 9 calls arrived later than 2 hours	97.5%
Dec	222	214	8 calls missed: 8 calls arrived later than 2 hours	96.4%
Total	2,251	2,180	As noted above.	96.8%

Witnesses: D. Brault
D. McIlwraith

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	3,994	4,123	96.9%
Feb	3,113	3,192	97.5%
Mar	3,501	3,573	98.0%
Apr	3,293	3,379	97.5%
May	3,838	3,932	97.6%
Jun	3,204	3,269	98.0%
Jul	3,120	3,220	96.9%
Aug	3,477	3,592	96.8%
Sep	3,384	3,530	95.9%
Oct	4,237	4,380	96.7%
Nov	4,361	4,519	96.5%
Dec	4,617	4,909	94.0%
Total	44,139	45,618	96.8%

Witnesses: D. Brault
D. McIlwraith

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.	2	2	100%
Feb.	1	1	100%
Mar.	0	0	0%
Apr.	1	1	100%
May	4	4	100%
Jun.	1	1	100%
Jul.	0	0	0%
Aug.	1	1	100%
Sept.	2	2	100%
Oct.	0	0	0%
Nov.	3	3	100%
Dec.	0	0	0%
TOTAL	15	15	100%

Witnesses: D. Brault
D. McIlwraith

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	472	501	94.2%
Feb	312	331	94.3%
Mar	366	383	95.6%
Apr	2,930	2,954	99.2%
May	3,740	3,810	98.2%
Jun	2,600	2,654	98.0%
Jul	2,234	2,289	97.6%
Aug	2,482	2,559	97.0%
Sep	2,554	2,672	95.6%
Oct	3,469	3,631	95.5%
Nov	2,250	2,506	89.8%
Dec	934	1,017	91.8%
Total	24,343	25,307	96.2%

Witnesses: D. Brault
D. McIlwraith

ENBRIDGE GAS DISTRIBUTION INC.
(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2017

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 generally accepted accounting principles 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) is responsible for all aspects related to governance of the Company. The Board has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Board reviews the consolidated financial statements and the internal controls as they relate to financial reporting. The Board approves 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)

James Sanders
President

(Signed)

Wendy Zelond
Vice President, Finance

February 16, 2018

February 16, 2018

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, 2017 and December 31, 2016 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with 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.

PricewaterhouseCoopers LLP
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215

pwc

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and their subsidiaries as at December 31, 2017 and December 31, 2016 and its financial performance and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2017**	2016
(millions of dollars)		
Operating Revenues		
Gas commodity and distribution revenue *(Note 18)*	**2,760**	2,437
Transportation of gas for customers	**418**	330
Other revenue *(Note 18)*	**114**	100
Total operating revenues	**3,292**	2,867
Operating Expenses		
Gas commodity and distribution costs *(Note 18)*	**2,032**	1,636
Operating and administrative *(Notes 12 and 18)*	**520**	534
Depreciation and amortization *(Notes 7 and 8)*	**330**	322
Earnings sharing *(Note 5)*	**24**	3
Total operating expenses	**2,906**	2,495
Operating Income	**386**	372
Other income *(Note 19)*	**64**	73
Interest expense, net *(Notes 10, 14 and 18)*	**(214)**	(206)
Earnings before income taxes	**236**	239
Income tax recovery/(expense) *(Note 15)*	**14**	(9)
Earnings	**250**	230
Preference share dividends *(Note 11)*	**(2)**	(2)
Earnings attributable to the common shareholder	**248**	228

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

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings	**250**	230
Other comprehensive income/(loss), net of tax *(Notes 13 and 14)*		
Change in unrealized loss on cash flow hedges	**—**	(11)
Reclassification to earnings of realized loss on cash flow hedges	**3**	5
Actuarial loss on other postretirement benefits (OPEB) *(Note 16)*	**(2)**	(1)
Foreign currency translation adjustment	**(2)**	(2)
Other comprehensive loss, net of tax	**(1)**	(9)
Comprehensive income	**249**	221
Preference share dividends	**(2)**	(2)
Comprehensive income attributable to the common shareholder	**247**	219

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

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Preference Shares *(Note 11)*	Common Shares *(Note 11)*	Additional Paid-in Capital	Retained Earnings/ (Deficit)	Accumulated Other Comprehensive Loss *(Note 13)*	Total
(millions of dollars)						
December 31, 2015	100	1,637	1,148	71	(6)	2,950
Other comprehensive loss, net of tax	—	—	—	—	(9)	(9)
Common shares issued	—	280	—	—	—	280
Earnings attributable to the common shareholder	—	—	—	228	—	228
Common shares dividends declared *(Note 18)*	—	—	—	(237)	—	(237)
December 31, 2016	100	1,917	1,148	62	(15)	3,212
Other comprehensive loss, net of tax	**—**	**—**	**—**	**—**	**(1)**	**(1)**
Common shares issued	**—**	**500**	**—**	**—**	**—**	**500**
Earnings attributable to the common shareholder	**—**	**—**	**—**	**248**	**—**	**248**
Common shares dividends declared *(Note 18)*	**—**	**—**	**—**	**(600)**	**—**	**(600)**
December 31, 2017	**100**	**2,417**	**1,148**	**(290)**	**(16)**	**3,359**

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

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2017**	2016
(millions of dollars)		
Operating activities		
Earnings	**250**	230
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization *(Notes 7 and 8)*	**330**	322
Deferred income tax expense *(Note 15)*	**(19)**	(22)
Net defined pension and other postretirement benefit obligations (OPEB) costs	**(25)**	30
Other	**1**	4
Changes in operating assets and liabilities *(Note 17)*	**27**	78
Net cash provided by operating activities	**564**	642
Investing activities		
Capital expenditures	**(407)**	(545)
Additions to intangible assets	**(392)**	(57)
Change in construction payable	**(1)**	(138)
Net cash used in investing activities	**(800)**	(740)
Financing activities		
Net change in short-term borrowings *(Note 10)*	**615**	(248)
Net change in short-term borrowings from affiliates *(Note 18)*	**—**	(6)
Term note issuances, net of issue costs *(Note 10)*	**298**	309
Term note repayments	**(500)**	(7)
Common shares issued *(Notes 11 and 18)*	**500**	280
Common share dividends	**(659)**	(233)
Preference share dividends	**(2)**	(2)
Net cash provided by financing activities	**252**	93
Net increase/(decrease) in cash and cash equivalents	**16**	(5)
Cash and cash equivalents at beginning of year	**4**	9
Cash and cash equivalents at end of year	**20**	4
Supplementary cash flow information		
Cash paid for income taxes	**4**	5
Cash paid for interest, net of amounts capitalized *(Note 10)*	**208**	194

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

ENBRIDGE GAS DISTRIBUTION INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2017**	2016
(millions of dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents *(Note 2)*	**20**	4
Restricted cash	**44**	58
Accounts receivable and other *(Notes 5, 6, 14 and 15)*	**849**	655
Due from affiliates *(Note 18)*	**43**	16
Gas inventory	**492**	512
Assets held for sale, current *(Note 4)*	**15**	—
	1,463	1,245
Property, plant and equipment, net *(Note 7)*	**7,532**	7,418
Investment in affiliate *(Notes 14 and 19)*	**825**	825
Deferred amounts and other assets *(Notes 5, 15 and 16)*	**597**	576
Intangible assets, net *(Note 8)*	**486**	158
Assets held for sale, long-term *(Note 4)*	**110**	—
Total assets	**11,013**	10,222
Liabilities and shareholders' equity		
Current liabilities		
Short-term borrowings *(Note 10)*	**960**	351
Short-term borrowings from affiliate *(Notes 10 and 18)*	**—**	34
Accounts payable and other *(Notes 5, 9, 14 and 16)*	**662**	807
Due to affiliates *(Note 18)*	**87**	95
Current portion of long-term debt *(Note 10)*	**—**	500
Liabilities held for sale, current *(Note 4)*	**43**	—
	1,752	1,787
Long-term debt *(Note 10)*	**3,760**	3,470
Other long-term liabilities *(Notes 5, 14 and 17)*	**1,142**	846
Deferred income taxes *(Note 15)*	**591**	532
Loans from affiliate *(Notes 10 and 18)*	**375**	375
Liabilities held for sale, long-term *(Note 4)*	**34**	—
Total liabilities	**7,654**	7,010
Shareholders' equity		
Share capital *(Note 11)*		
Preference shares *(convertible; 4 outstanding at December 31, 2017 and December 31, 2016)*	**100**	100
Common shares *(213 and 186 outstanding at December 31, 2017 and 2016, respectively)*	**2,417**	1,917
Additional paid-in capital	**1,148**	1,148
Retained earnings/(deficit)	**(290)**	62
Accumulated other comprehensive loss *(Note 13)*	**(16)**	(15)
Total shareholders' equity	**3,359**	3,212
Total liabilities and shareholders' equity	**11,013**	10,222

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

Approved by the Board of Directors:

(Signed)

James Sanders
President

(Signed)

David G. Unruh
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS OVERVIEW

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence Gas), an asset held for sale *(Note 4)*. The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

2. SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. The Company is in the process of obtaining further extension of this exemptive relief beyond January 1, 2019.

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; unbilled revenues; allowance for doubtful accounts; carrying value of gas inventory; depreciation rates and carrying value of property, plant and equipment; amortization rates and carrying value of intangible assets; valuation of stock-based compensation; fair value of financial instruments; provisions for income taxes; assumptions used to measure retirement and OPEB; commitments and contingencies; and fair value of asset retirement obligations (ARO). Actual results could differ from these estimates.

Effective September 30, 2017, the Company combined Cash and cash equivalents and amounts previously presented as Bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements. As at December 31, 2017, $4 million (2016 - $72 million) of Bank indebtedness has been combined with Cash and cash equivalents on the Company's Consolidated Statements of Financial Position. Net cash provided by financing activities in the Company's Consolidated Statements of Cash Flows have been reduced by $45 million for the year ended December 31, 2016 to reflect this change.

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 *(Note 4)*.

REGULATION

The utility operations of the Company within Ontario are regulated by the Ontario Energy Board (OEB), while the utility operations of St. Lawrence Gas 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 5)*.

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.

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.

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 and foreign exchange. 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, 2017 or 2016.

Cash Flow Hedges
The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenue and 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 non-current 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 as a direct deduction from the carrying amount of the related debt liability. These costs are amortized using the effective interest rate method over the life of the related debt instrument and are recorded in Interest expense.

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. Deferred tax liabilities and assets are classified as noncurrent in the Consolidated Statements of Financial Position.

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 5)*.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions 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 Gas, is the United States dollar (USD). The effects of translating the financial statements of St. Lawrence Gas 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, net of bank indebtedness that is subject to cash pooling arrangements.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific agreements, are presented as Restricted cash on the Consolidated Statements of Financial Position. Restricted cash represents funds received from the Green Investment Fund program. The cash flow impact of this item is included in changes of operating assets and liabilities on the Consolidated Statements of Cash Flows.

GAS INVENTORY
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 as 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; and derivative financial instruments.

INTANGIBLE ASSETS
Prior to January 1, 2017, Intangible assets consisted primarily of the Company's Customer Information System (CIS) and software costs, including the Work and Asset Management Solution (WAMS). The Company capitalizes costs incurred during the application development stage of internal use software projects. Those intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use. Beginning January 1, 2017, intangible assets also include emission allowances purchased in order to meet greenhouse gas compliance obligations *(Note 8)*.

ASSET RETIREMENT OBLIGATIONS
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.

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.

The Company uses mortality tables issued by the Canadian Institute of Actuaries tables (revised in 2014) to measure its benefit obligations of its pension plan. 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 anticipate 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;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;
- Amortization of the 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; 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 contribution occurs.

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 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 ratemaking 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, 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

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.

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 Enbridge's shares.

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 a liability has been incurred, and the amount of the 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

ADOPTION OF NEW STANDARDS

Clarifying the Definition of a Business in an Acquisition

Effective January 1, 2017, the Company early adopted ASU 2017-01 on a prospective basis. The new standard was issued with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses.

Accounting for Intra-Entity Asset Transfers
Effective January 1, 2017, the Company early adopted ASU 2016-16 on a modified retrospective basis. The new standard was issued with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting
Effective January 1, 2017, the Company adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES
Improvements to Accounting for Hedging Activities
ASU 2017-12 was issued in August 2017 with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The accounting update allows cash flow hedging of contractually specified components in financial and non-financial items. Under the new guidance, hedge ineffectiveness is no longer required to be measured and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The ASU also allows the initial quantitative hedge effectiveness assessment to be performed at any time before the end of the quarter in which the hedge is designated. After initial quantitative testing is performed, an ongoing qualitative effectiveness assessment is permitted. The accounting update is effective January 1, 2019, with early adoption permitted, and is to be applied on a modified retrospective basis. The Company is currently assessing the impact of the new standard on its Consolidated Financial Statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation
ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans
ASU 2017-07 was issued in March 2017 primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. In addition, only the service cost component of net benefit cost is eligible for capitalization. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis for the statement of earnings presentation component and a prospective basis for the capitalization component. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets
ASU 2017-05 was issued in February 2017 with the intent of clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The ASU clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The accounting update is

effective January 1, 2018 and will be applied on a modified retrospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows
ASU 2016-18 was issued in November 2016 with the intent to clarify guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows. The accounting update requires that changes in restricted cash and restricted cash equivalents be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. The Company currently presents the changes in restricted cash and restricted cash equivalents under operating activities in the Consolidated Statement of Cash Flows. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company will amend the presentation in the Consolidated Statement of Cash Flows to include restricted cash and restricted cash equivalents with cash and cash equivalents and retrospectively reclassify all periods presented.

Simplifying Cash Flow Classification
ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statement of Cash Flows. The new guidance addresses eight specific presentation issues. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company has assessed each of the eight specific presentation issues and the adoption of this ASU does not have a material impact on the consolidated financial statements.

Accounting for Credit Losses
ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective January 1, 2020.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The Company is currently gathering a complete inventory of its lease contracts in order to assess the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018 and is to be applied using a modified retrospective approach.

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. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative and are recorded at

cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial instruments for disclosure purposes is measured using exit price. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Revenue from Contracts with Customers
ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the present standards in addition to additional disclosures. The new standard is effective January 1, 2018. The new standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company has decided to adopt the new standard using the modified retrospective method.

The Company has reviewed its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on the Company's assessment, the application of the standard will result in a change in presentation for payments to customers under an earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments will be reflected as a reduction of revenue. The Company does not expect that these changes will have a material impact on revenue or earnings. The Company has also developed and tested processes to generate the disclosures which will be required under the new standard commencing in Q1 2018.

4. ASSETS HELD FOR SALE

In August 2017, the Company entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas for cash proceeds of approximately $88 million (US $70 million). Subject to regulatory approval and certain pre-closing conditions, the transaction is expected to close in 2018. As at December 31, 2017, St. Lawrence Gas was classified as held for sale and the related assets and liabilities were measured at the lower of their carrying value and fair value less costs to sell. Included within Assets held for sale, long-term is $94 million related to Property, plant and equipment, net. No impairment loss was recognized on the classification of St. Lawrence Gas as held for sale. Any gain or loss on the sale will be measured and recorded at the date that the transaction closes.

5. REGULATORY MATTERS

RATE APPROVALS
Enbridge Gas Distribution
For the year ended December 31, 2017, the Company's rates were set according to the OEB Decision and Rate Order (December 2016) in the Company's 2017 rate application. The rates approved as part of the 2017 rate application represented the fourth 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. The customized IR plan requires the Company to update select items in each of 2015 through 2018, in order to establish final allowed revenues and rates.

Effective January 1, 2017, in accordance with the OEB's Interim Rate Order (November 2016) in the Company's 2017 Cap and Trade Compliance Plan application, the Company also commenced charging customers interim cap and trade unit rates. The interim cap and trade unit rates were confirmed as final cap and trade unit rates, as per the OEB's Decision and Rate Order (November 2017) in the aforementioned application.

For the year ended December 31, 2016, the Company's rates were set according to the OEB approved settlement agreement (December 2015) in the Company's 2016 rate application, updated to reflect the OEB's decision and final rate order (May 2016) in the Company's multi-year demand side management (DSM) application.

Under the customized IR plan, the Company has continued to apply the accounting guidance found in Accounting Standards Codification (ASC) 980 - Regulated Operations.

St. Lawrence Gas

St. Lawrence Gas is currently in a rate year ending May 31, 2018, according to the recent NYSPSC order establishing a three year rate plan covering the period of June 1, 2016 through May 31, 2019. For the years ended December 31, 2017 and 2016, St. Lawrence Gas' rates were set using a Cost of Service (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.

The calculation of earnings sharing is on an annual basis for each rate year period commencing June 1, 2016. For the fiscal rate years ending May 31, 2018 and 2017, any earnings above the approved return on equity and between 9.5% to 10.0% will be shared 50/50 between customers and the Company; from 10.0% to 10.5%, 80/20; and over 10.5%, 90/10.

Under COS, it is the responsibility of St. Lawrence Gas to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

During the years ended December 31, 2017 and 2016, 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 2017 included an after-tax rate of return on common equity of 8.78% (2016 - 9.19%) based on a 36% (2016 - 36%) deemed common equity component of rate base.

St. Lawrence Gas

St. Lawrence Gas' approved after-tax rate of return on common equity embedded in rates was 9.0% for the rate year ended May 31, 2018 (fiscal 2016 - 9.0%) based on a 48% (fiscal 2016 - 48%) deemed common equity component of rate base.

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2017**	2016	Consolidated Statement of Financial Position Location
(millions of dollars)			
Current regulatory assets			
Purchase gas variance[1]	**55**	5	AR
Other current regulatory assets	**78**	61	AR
Total current regulatory assets	**133**	66	
Long-term regulatory assets			
Deferred income taxes[2]	**468**	381	DA
Pension plan receivable[3]	**42**	60	DA
OPEB[4]	**67**	71	DA
Other long-term regulatory assets	**18**	56	DA
Total long-term regulatory assets	**595**	568	
Total regulatory assets	**728**	634	
Current regulatory liabilities			
Site restoration clearance adjustment[5]	**31**	77	AP
Other regulatory liabilities	**45**	19	AP
Total current regulatory liabilities	**76**	96	
Long-term regulatory liabilities			
Future removal and site restoration reserves[6]	**603**	577	OLTL
Site restoration clearance adjustment[5]	**—**	32	OLTL
Other regulatory liabilities	**8**	15	OLTL
Total long-term regulatory liabilities	**611**	624	
Total regulatory liabilities	**687**	720	

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

1 *Purchase gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates.*

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

3 *The pension plan balance represents the regulatory offset to the pension liability to the extent the amounts are to be collected 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.*

4 *The OPEB balance represents the Company's right to recover OPEB costs resulting from the adoption of the accrual basis of accounting for OPEB costs upon transition to US GAAP in 2012. Pursuant to the OEB rate order, the amount as at December 31, 2012 is to be collected in rates over a 20-year period that commenced in 2013. In the absence of rate regulation accounting, this regulatory balance and related earnings impact would not be recorded.*

5 *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.*

6 *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.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Operating Cost Capitalization

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.

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, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2017, the net book value of these costs included in gas mains in Property, plant and equipment, net was $118 million (2016 - $125 million). In the absence of rate regulation accounting, some of these costs would be charged to earnings in the year incurred.

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2017, the net book value of these costs included in intangible assets was $22 million (2016 - $35 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.

WAMS is the Company's new integrated work and asset management solution. At December 31, 2017, the net book value of the asset included in intangible assets was $77 million (2016 - $84 million). In the absence of rate regulation accounting, a portion of the original cost of the asset 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, 2017 is $55 million (2016 - $49 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.

6. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2017**	2016
(millions of dollars)		
Trade receivables	**373**	327
Unbilled revenues	**209**	135
Regulatory assets *(Note 5)*	**133**	66
Other	**163**	160
Allowance for doubtful accounts *(Note 14)*	**(29)**	(33)
	849	655

7. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2017**	2016
(millions of dollars)			
Regulated property, plant and equipment			
Gas mains	**2.2%**	**4,717**	4,637
Gas services	**2.3%**	**3,157**	3,065
Regulating and metering equipment	**5.2%**	**1,012**	963
Gas storage	**1.9%**	**379**	366
Right-of-way	**1.2%**	**112**	106
Computer technology	**32.6%**	**30**	33
Under construction	**—**	**109**	130
Construction materials inventory	**—**	**37**	34
Land	**—**	**28**	28
Other	**6.8%**	**298**	300
		9,879	9,662
Accumulated depreciation		**(2,435)**	(2,334)
		7,444	7,328
Unregulated property, plant and equipment			
Gas storage	**1.9%**	**89**	90
Other	**0.5%**	**18**	23
		107	113
Accumulated depreciation		**(19)**	(23)
		88	90
Property, plant and equipment, net		**7,532**	7,418

Depreciation expense, including amounts collected for future removal and site restoration costs, was $268 million for the year ended December 31, 2017 (2016 - $266 million).

The Company incurred approximately $15 million for the year ended December 31, 2017 (2016 - $15 million) in incremental depreciation resulting from push-down accounting *(Note 2)*.

8. INTANGIBLE ASSETS

December 31,	2017	2016
(millions of dollars)		
Intangible assets	**779**	**406**
Less: Accumulated amortization	**(293)**	**(248)**
Intangible assets, net	**486**	**158**

Intangible assets consists of software, CIS, and emission allowances. Beginning January 1, 2017, emission allowances were purchased by the Company for itself and most of its customers in order to meet greenhouse gas compliance obligations in the Province of Ontario. Purchased emission allowances are recorded at their original cost and are not amortized, as they will be used to satisfy compliance obligations as they come due. For the year ended December 31, 2017, the weighted average amortization rate for software and CIS were 18.8% and 10.0% respectively (2016 - 22.2% and 10.0% respectively).

Intangible assets include $15 million of work-in-progress as at December 31, 2017 (2016 - $12 million). Total amortization expense for intangible assets was $62 million for the year ended December 31, 2017 (2016 - $56 million). The Company expects aggregate amortization expense for the years ending

December 31, 2018 through 2022 of $68 million, $59 million, $62 million, $64 million and $65 million, respectively.

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2017**	2016
(millions of dollars)		
Accrued liabilities	**325**	371
Trade payables	**94**	82
Regulatory liabilities *(Note 5)*	**76**	96
Other	**167**	258
	662	807

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2017**	2016
(millions of dollars)				
Debenture	9.85%	2024	**85**	85
Medium-term notes[1]	4.47%	2020-2050	**3,695**	3,895
Commercial paper and credit facility draws, net			**960**	360
Other[2]			**(20)**	15
Total debt			**4,720**	4,355
Current maturities			**—**	(500)
Short-term borrowings	1.43%		**(960)**	(351)
Short-term borrowings from affiliates[3] *(Note 18)*			**—**	(34)
Long-term debt			**3,760**	3,470
Loans from affiliate company *(Note 18)*			**375**	375

1 The balance in 2017 pertaining to St. Lawrence Gas amounting to approximately $9 million is presented as Liabilities held for sale, long-term (Note 4) on the Consolidated Statements of Financial Position.
2 Consists of note payable to affiliate company, debt premium and/or debt issuance costs.
3 The balance in 2017 pertaining to St. Lawrence Gas amounting to approximately $30 million is presented as Liabilities held for sale, current (Note 4) on the Consolidated Statements of Financial Position.

In November 2017, the Company issued $300 million of thirty-year medium-term notes (MTNs) at an interest rate of 3.51% payable semi-annually in arrears. This MTN matures in November 2047.

In August 2016, the Company issued $300 million of ten-year MTNs at an interest rate of 2.50% payable semi-annually in arrears. This MTN matures in August 2026.

For the years ending December 31, 2018 through 2022, medium-term note maturities are nil, nil, $400 million, $175 million and nil, respectively. The Company's debentures and medium-term notes bear interest at fixed rates, and interest obligations for the years ending December 31, 2018 through 2022 are $174 million, $174 million, $174 million, $157 million and $149 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2017**	2016
(millions of dollars)		
Debentures and medium-term notes	**176**	176
Loans from affiliate company *(Note 18)*	**28**	27
Commercial paper and credit facility draws	**8**	7
Other interest and finance costs	**7**	10
Capitalized	**(5)**	(14)
	214	206

In 2017, total interest paid to third parties was $185 million (2016 - $181 million) and total interest paid to affiliates was $28 million (2016 - $27 million).

The Company's borrowings, whether debentures or MTNs, are unsecured. As at December 31, 2017, 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 2017, the Company extended the term out date of this external credit facility to July 2018, with a maturity date in July 2019.

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, 2017.

		December 31, 2017			December 31, 2016
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of dollars)					
Enbridge Gas Distribution Inc.	2019	**1,000**	**960**	**40**	1,000
St. Lawrence Gas Company, Inc.	2019	**16**	**12**	**4**	17
Total credit facilities		**1,016**	**972**	**44**	1,017

1 Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility. St. Lawrence Gas draws are shown as Liabilities held for sale, current and long-term on the Consolidated Statements of Financial Position.

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

11. 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

	2017		2016	
December 31,	Number of shares	Amount	Number of shares	Amount
(millions of dollars; number of common shares in millions)				
Balance at beginning of year	**185.6**	**1,917**	170.0	1,637
Common shares issued	**27.7**	**500**	15.6	280
Balance at end of year *(Note 18)*	**213.3**	**2,417**	185.6	1,917

PREFERENCE SHARES

December 31, 2017 and 2016	Authorized	Issued and Outstanding	Amount
(millions of dollars, number of preference shares in millions)			
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	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, 2017, 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 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.

12. 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 at December 31, 2017, the Company did not have any employees that had options in the PSO Plan.

INCENTIVE STOCK OPTIONS
(options in thousands)
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.

Compensation expense recorded for the year ended December 31, 2017 for ISOs was $5 million (2016 - $6 million). At December 31, 2017, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $2 million. The cost is expected to be fully recognized over a weighted average period of approximately three years. As at December 31, 2017, there were 2,838 ISOs outstanding (2016 - 3,476 ISOs outstanding).

PERFORMANCE STOCK UNITS
(units in thousands)
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 performance multiplier is derived 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.

Compensation expense recorded for the year ended December 31, 2017 for PSUs was nil (2016 - $4 million). As at December 31, 2017, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $1 million and is expected to be fully recognized over a weighted average period of approximately two years. As at December 31, 2017, there were 19 PSUs outstanding (2016 - 35 PSUs outstanding).

RESTRICTED STOCK UNITS
(units in thousands)
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.

Compensation expense recorded for the year ended December 31, 2017 for RSUs was $5 million (2016 - $6 million). As at December 31, 2017, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $5 million and is expected to be fully recognized over a weighted average period of approximately two years. As at December 31, 2017, there were 165 RSUs outstanding (2016 - 187 RSUs outstanding).

13. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

Changes in AOCI for the years ended December 31, 2017 and 2016 are as follows:

	2017			
	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of dollars)				
Balance at January 1, 2017	**(11)**	**4**	**(8)**	**(15)**
Other comprehensive loss retained in AOCI	**—**	**(2)**	**(2)**	**(4)**
Other comprehensive loss reclassified to earnings	**4**	**—**	**—**	**4**
	(7)	**2**	**(10)**	**(15)**
Tax Impact				
Income tax on amounts retained in AOCI	**(1)**	**—**	**—**	**(1)**
Income tax on amounts reclassified to earnings	**—**	**—**	**—**	**—**
	(1)	**—**	**—**	**(1)**
Balance at December 31, 2017	**(8)**	**2**	**(10)**	**(16)**

	2016			
	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of dollars)				
Balance at January 1, 2016	(5)	6	(7)	(6)
Other comprehensive income/(loss) retained in AOCI	(14)	(2)	(2)	(18)
Other comprehensive loss reclassified to earnings	6	—	—	6
	(13)	4	(9)	(18)
Tax Impact				
Income tax on amounts retained in AOCI	3	—	—	3
Income tax on amounts reclassified to earnings	(1)	—	1	—
	2	—	1	3
Balance at December 31, 2016	(11)	4	(8)	(15)

14. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in natural gas prices, emission allowance prices, foreign exchange rates and interest rates (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.

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 customers; therefore, the net exposure to the Company is zero.

Emission Allowance Price Risk

Emission allowance price risk is the risk of gain or loss due to changes in the market price of emission allowances that the Company is required to purchase for itself and most of its customers to meet greenhouse gas compliance obligations under the Ontario Cap and Trade framework. Similar to the gas supply procurement framework, the OEB's framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates, subject to OEB approval.

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 United States dollars (USD). As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from USD exchange rate variability.

The Company implemented a policy in 2016 to hedge a portion of USD denominated unregulated storage revenue exposures. Qualifying derivative instruments were used to hedge anticipated USD denominated revenues and to manage variability in cash flows through September 2017. During September 2017, the Company assigned its USD denominated unregulated storage contracts to Union Gas Limited (Union Gas), an affiliated company under common control as a result of the merger transaction *(Note 18)*. The Company has also novated all of its qualifying derivative instruments relating to forward exchange contracts to Union Gas.

A portion of the Company's purchases of natural gas are denominated in USD and as a result there is exposure to fluctuations in the exchange rate of the USD 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 were used through January 2017 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 were used during 2016 to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances.

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.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the financial statement line item in the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges or net investment hedges at December 31, 2017 or December 31, 2016.

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, 2017	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 dollars)					
Other long-term liabilities					
Foreign exchange contracts	—	—	—	—	—
Total net derivative liabilities					
Foreign exchange contracts	—	—	—	—	—

December 31, 2016	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 dollars)					
Other long-term liabilities					
Foreign exchange contracts	(1)	—	(1)	—	(1)
Total net derivative liabilities					
Foreign exchange contracts	(1)	—	(1)	—	(1)

The Company did not have any outstanding derivative instruments relating to interest rate contracts as at December 31, 2017. Derivative instruments relating to interest rate contracts as at December 31, 2016 had a notional principal of $8 million for interest rate contracts for short-term borrowings and zero for interest rate contracts on the anticipated issuance of long-term debt.

The Company did not have any outstanding derivative instruments relating to forward exchange contracts as at December 31, 2017. At December 31, 2016 the Company's derivative instruments relating to foreign exchange forward contracts matured through 2023 and had a notional principal of $13 million (US $10 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,	**2017**	2016
(millions of dollars)		
Amount of unrealized loss recognized in OCI cash flow hedges		
Interest rate contracts	—	(13)
Foreign exchange contracts	—	(1)
	—	(14)
Amount of loss reclassified from AOCI to earnings *(effective portion)*		
Interest rate contracts[1]	**(4)**	(3)
	(4)	(3)
Amount of loss reclassified from AOCI to earnings *(ineffective portion)*		
Interest rate contracts[1]	—	(3)
	—	(3)

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

The Company estimates that no amount in AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature.

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, draws under committed credit facilities and long-term debt, which includes debentures and medium term notes (MTNs) 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 also 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 as at December 31, 2017. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. 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 obtained 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, which totaled $29 million at December 31, 2017 (December 31, 2016 - $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. 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 concentrations, with respect to derivative instruments, in the Canadian, United States, European, Asian or other financial institutions counterparty segments at December 31, 2017 or December 31, 2016.

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 are 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 FINANCIAL INSTRUMENTS

The Company categorizes its derivative instruments 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 a 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, foreign exchange, 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, 2017, the Company had Level 2 derivative assets with fair value of nil (2016 - nil) and Level 2 derivative liabilities with fair value of nil (2016 - $1 million). The Company’s policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers between levels as at December 31, 2017 or December 31, 2016.

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, 2017, the fair value of the investment was $825 million (2016 - $825 million). The fair value of the Company’s investment is classified as a Level 2 measurement and as at December 31, 2017 and 2016 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, 2017, the Company’s long-term debt, including the current portion had a carrying value of $3,780 million (2016 - $3,983 million) before debt issue costs and a fair value of $4,363 million (2016 - $4,585 million).

The fair value of other financial assets and liabilities other than derivative instruments and long-term debt approximate their cost due to the short period to maturity.

15. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings before income taxes	**236**	239
Federal statutory income tax rate	**15.0 %**	15.0%
Federal income taxes at statutory rate	**35**	36
Increase/(decrease) resulting from:		
Provincial and state income taxes	**(11)**	(27)
Effects of rate regulated accounting[1,2]	**(36)**	(25)
Non-taxable intercompany distributions[2]	**(9)**	(9)
Part VI.1 tax, net of federal Part I tax deduction[2]	**—**	35
Investment in foreign subsidiaries held for sale *(Note 4)*	**4**	—
Other[3]	**3**	(1)
Income tax expense/(recovery)	**(14)**	9
Effective income tax rate	**(5.9)%**	3.8%

1 During 2017, 2016, 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 $21 million at December 31, 2017 (2016 - $22 million).
2 The provincial tax component of these items is included in “Provincial and state income taxes” above.
3 Included in “Other” are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings before income taxes		
Canada	**232**	236
United States	**4**	3
	236	239
Current income taxes		
Canada	**5**	32
United States	**—**	(1)
	5	31
Deferred income taxes		
Canada	**(20)**	(24)
United States	**1**	2
	(19)	(22)
Income tax expense/(recovery)	**(14)**	9

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,	**2017**	2016
(millions of dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(662)**	(637)
Regulatory assets	**(124)**	(101)
Deferrals	**(24)**	(8)
Other	**(4)**	—
Total deferred income tax liabilities	**(814)**	(746)
Deferred income tax assets		
Future removal and site restoration reserves	**160**	153
Retirement and postretirement benefits	**31**	37
Minimum tax credits	**12**	13
Loss carryforwards	**13**	4
Financial derivatives	**3**	4
Other	**4**	3
Total deferred income tax assets	**223**	214
Net deferred income tax liabilities	**(591)**	(532)

In 2017, the investment in St. Lawrence Gas was classified as held for sale. The Company is no longer asserting permanent reinvestment for this foreign subsidiary's earnings. As such, it recorded a deferred tax liability of $4 million on the difference between the carrying value of this foreign subsidiary and its corresponding tax basis. This difference is largely a result of unremitted earnings and currency translation adjustments.

In 2016, the Company did not provide for deferred taxes on this difference as the earnings in this subsidiary were intended to be permanently reinvested in its operations. As such, this investment was not anticipated to give rise to income taxes in the foreseeable future. The unremitted earnings and currency translation adjustment for which no deferred taxes were provided in 2016 was $30 million.

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 is open to examination by Canadian tax authorities for the 2012 to 2017 tax years. The Company is currently under examination for income tax matters in Canada for the 2015 to 2016 tax years.

UNRECOGNIZED TAX BENEFITS

The Company has no unrecognized tax benefits related to uncertain tax positions as at December 31, 2017 and 2016 and no accrued interest or penalties thereon.

16. PENSION AND OTHER POSTRETIREMENT BENEFITS

PENSION PLANS

Substantially all of the Company's employees participate in non-contributory pension plans which provide defined benefit and/or defined contribution pension benefits. The Company also maintains supplemental pension plans that provide pension benefits in excess of the basic plan for certain employees.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on each plan participant's years of service and final average remuneration. These benefits are partially inflation-indexed after a plan participant's retirement. The Company's contributions are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities.

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

OTHER POSTRETIREMENT BENEFITS
OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees on a non-contributory basis.

BENEFIT OBLIGATIONS AND FUNDED STATUS
The following table details 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.

	Pension		OPEB	
December 31,	**2017**	2016	**2017**	2016
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,098**	1,025	**123**	120
Service cost	**33**	32	**2**	1
Interest cost	**36**	35	**4**	5
Actuarial loss	**43**	51	**1**	2
Benefits paid	**(58)**	(46)	**(4)**	(4)
Other	**(16)**	1	**(14)**	(1)
Benefit obligation at end of year[1]	**1,136**	**1,098**	**112**	**123**
Change in plan assets				
Fair value of plan assets at beginning of year	**998**	969	**17**	17
Actual return on plan assets	**107**	73	**2**	1
Employer's contributions	**47**	1	**4**	5
Benefits paid	**(58)**	(46)	**(4)**	(4)
Other	**(7)**	1	**(19)**	(2)
Fair value of plan assets at end of year	**1,087**	**998**	**—**	**17**
Underfunded status at end of year	**(49)**	**(100)**	**(112)**	**(106)**
Presented as follows:				
Deferred amounts and other assets	**2**	3	**—**	3
Accounts payable and other *(Note 9)*	**—**	—	**(4)**	(4)
Other long-term liabilities	**(51)**	(103)	**(108)**	(105)

1 For pension plans, the benefit obligation is the projected obligation. For OPEB plans, the benefit obligations is the accumulated postretirement benefit obligation. The accumulated benefit obligation for the Company's pension plans was $1,051 million as at December 31, 2017 (2016 - $991 million).

At December 31, 2017, pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $54 million (2016 - $106 million), accumulated benefit obligations of $1,109 million (2016 - $1,072 million) and plan assets with a fair value of $1,055 million (2016 - $966 million).

AMOUNTS RECOGNIZED IN OTHER COMPREHENSIVE INCOME
The net actuarial loss included in AOCI, before tax, was $12 million relating to the Company's OPEB plans as at December 31, 2017 (2016 - $11 million).

NET BENEFIT COST RECOGNIZED

The components of net benefit cost and other amounts recognized in pre-tax OCI related to the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2017**	2016	**2017**	2016
(millions of Canadian dollars)				
Service cost	**33**	32	**2**	1
Interest cost	**36**	35	**4**	5
Expected return on plan assets	**(63)**	(60)	**(1)**	(1)
Amortization of actuarial loss	**17**	14	**—**	—
Net defined benefit and OPEB costs	**23**	21	**5**	5
Defined contribution benefit costs	**1**	1	**—**	—
Net benefit cost recognized in Earnings	**24**	**22**	**5**	**5**
Amount recognized in OCI				
Net actuarial loss arising during the year	**—**	—	**2**	2
Total amount recognized in OCI	**—**	—	**2**	2
Total amount recognized in Comprehensive income	**24**	22	**7**	7

The Company estimates that approximately $14 million related to pension plans and OPEB plans as at December 31, 2017 will be reclassified from AOCI into earnings in the next 12 months.

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 5)*. For the year ended December 31, 2017 there were nominal differences between pension expense for accounting purposes and pension expense for ratemaking purposes. For the year ended December 31, 2016, an offsetting regulatory liability increased by $10 million and has been recorded to the extent pension and OPEB costs are expected to be refunded to customers in future rates.

ACTUARIAL ASSUMPTIONS

The weighted average assumptions made in the measurement of the benefit obligations and net benefit cost of the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
Year ended December 31,	**2017**	2016	**2017**	2016
Benefit obligations				
Discount rate	**3.6%**	3.9%	**3.6%**	3.9%
Rate of salary increase	**3.2%**	3.5%	**3.2%**	3.5%
Net benefit cost				
Discount rate - service cost	**4.1%**	4.3%	**4.1%**	4.3%
Discount rate - interest cost	**3.9%**	3.5%	**4.0%**	3.5%
Rate of return on plan assets	**6.4%**	6.5%	**0.0%**	6.0%
Rate of salary increase	**3.5%**	3.4%	**3.5%**	3.4%

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.

ASSUMED HEALTH CARE COST TRENDS

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

	2017	2016
Health care cost trend rate assumed for next year	**5.5%**	5.6%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.3%**	4.3%
Year that the rate reaches the ultimate trend rate	**2034**	2034

A 1% point change in the assumed health care cost trend rate would have the following effects for the year ended and as at December 31, 2017:

	1% Point Increase	1% Point Decrease
(in millions of dollars)		
Effect on total service and interest costs	—	—
Effect on accumulated postretirement benefit obligation	14	(11)

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 Company's operating environment and financial situation 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 asset allocation targets and major categories of plan assets are as follows:

Asset Category	Target Allocation	December 31, 2017	2016
Equity securities	46-70%	**48.5%**	47.0%
Fixed income securities	30-36%	**34.0%**	36.0%
Other	0-18%	**17.5%**	17.0%

The following table summarizes the fair value of the plan assets for the Company's pension and OPEB plans recorded at each fair value hierarchy level.

	2017				2016			
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	**15**	**—**	**—**	**15**	7	—	—	7
Equity securities								—
United Stated	**208**	**—**	**—**	**208**	110	—	—	110
Canada	**228**	**—**	**—**	**228**	209	—	—	209
Global	**85**		**—**	**85**	74	72	—	146
Fixed income securities								—
Government	**225**	**—**	**—**	**225**	204	—	—	204
Corporate	**141**	**—**	**—**	**141**	145	—	—	145
Infrastructure and real estate	**—**	**—**	**178**	**178**	—	—	153	153
Forward currency contracts	**—**	**(5)**	**—**	**(5)**	—	—	—	—
	902	**(5)**	**178**	**1,075**	749	72	153	974
Non-financial instruments	**—**	**—**	**—**	**12**	—	—	—	24
Total pension plan assets at fair value				**1,087**				**998**
OPEB								
Equity securities								
United States	**—**	**—**	**—**	**—**	5	—	—	5
Global	**—**	**—**	**—**	**—**	5	—	—	5
Fixed income securities								—
Government	**—**	**—**	**—**	**—**	7	—	—	7
Total OPEB plan assets at fair value	**—**	**—**	**—**	**—**	**17**	—	—	17

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 values of the infrastructure and real estate investments 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,	**2017**	2016
(millions of dollars)		
Balance at beginning of year	**153**	147
Unrealized and realized gains	**17**	13
Purchases and settlements, net	**8**	(7)
Balance at end of year	**178**	153

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2018	2019	2020	2021	2022	2023 - 2027
(millions of Canadian dollars)						
Pension	50	52	53	55	57	307
OPEB	5	5	5	5	4	26

17. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2017**	2016
(millions of dollars)		
Restricted cash	**15**	(58)
Accounts receivable and other[1,2]	**(169)**	(39)
Gas inventory	**20**	35
Regulatory assets *(Note 5)*	**(7)**	158
Deferred amounts and other assets[1]	**(34)**	—
Accounts payable and other[1,2]	**(61)**	109
Regulatory liabilities *(Note 5)*	**(102)**	(127)
Cap and trade compliance liability[3]	**365**	—
	27	78

1 The cash flow impacts of regulatory assets and liabilities have been separately disclosed and are not included.
2 Includes amounts related to affiliated companies.
3 Under cap and trade regulation in the Province of Ontario, the Company is required to meet greenhouse gas compliance obligations for most of its customers' use of natural gas as well as emissions from its own operations. The Company will be required to relieve its compliance liability, through the submission of emission allowances, following the completion of the initial compliance period of January 1, 2017 through December 31, 2020. The balance in 2017 is presented as Other long-term liabilities on the Consolidated Statements of Financial Position.

18. 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,	**2017**	2016
(millions of dollars)		
Enbridge Energy Distribution Inc.		
Common share dividends declared	**600**	237
Union Gas[1]		
Purchase of gas storage and transportation services	**112**	—
Revenue from unregulated storage capacity	**5**	—
IPL System Inc.		
Dividend income	**63**	63
Interest expense (Note 10)	**27**	27
Enbridge		
Purchase of treasury and other management services	**49**	49
Part VI.1 tax reimbursement (Note 15)	**—**	5
Tidal Energy Marketing Inc.		
Purchase of natural gas	**54**	24
Revenue from optimization services	**9**	8
Revenue from unregulated storage capacity	**2**	2
Tidal Energy Marketing (U.S.) LLC		
Purchase of natural gas	**56**	26
Aux Sable Canada LP		
Purchase of natural gas	**—**	16
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**30**	30
Other related entities		
Purchase of gas transportation services	**25**	31

1 On February 27, 2017, Enbridge and Spectra Energy Corp. (Spectra) combined, to complete a merger transaction. The Company purchases gas storage and transportation services from Union Gas, an indirectly wholly owned subsidiary of Spectra, at prevailing market prices and under normal trade terms. The purchase of gas storage and transportation services and revenue from unregulated storage capacity from Union Gas includes only 10 months of activity subsequent to the merger transaction.

The Company had related party balances as follows:

December 31,	2017	2016
(millions of dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**2,417**	1,917
Dividend payable	**—**	59
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**9**	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	30	34
Other accounts receivable/(payable)		
Other related entities, net	**(40)**	(23)

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, 2017, the investment of $825 million (2016 - $825 million) in these shares resulted in a weighted average dividend yield of 7.6%.

At December 31, 2017, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.9% and $175 million at 7.5%). 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, 2017, interest paid amounted to $27 million (2016 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 1.1% 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.

Part VI.1 Tax Reimbursement
The Company entered into an agreement with Enbridge for the transfer of Part VI.1 tax and the related Part I tax deduction. The Company received a non-taxable reimbursement relating to the transfer.

Natural Gas Purchases
The Company 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 under normal trade terms. Contractual obligations under the Tidal Energy Marketing (U.S.) LLC and Tidal Energy Marketing Inc. contracts are 2018 to 2019 - $32 million, 2020 to 2021 - nil, and thereafter - nil.

Optimization Services
The Company provides pipeline and storage optimization services to Tidal Energy Marketing Inc., an affiliated entity under common control.

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 Storage and Transportation Services
The Company 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, Niagara Gas Transmission Limited, 2193914 Canada Limited and Union Gas. The Company also contracted for natural gas storage services from Union Gas. Contractual obligations under the Union Gas, Vector Pipeline Limited Partnership (U.S.) and Vector Pipeline Limited Partnership (Canadian) are 2018 to 2019 - $316 million, 2020 to 2021 - $280 million and thereafter - $358 million.

Unregulated Storage Services
On July 31, 2017, the Company entered into a Gas Storage Service Agreement (GSSA) with Union Gas, whereby Union Gas contracted all of the Company's unregulated storage space and deliverability effective September 2017.

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.

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

19. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
At December 31, 2017, the Company had commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of dollars)							
Purchase of services, pipe and other materials, including transportation[1,2]	4,954	1,073	841	614	489	435	1,502

1 Includes capital and operating commitments.

2 Included in these amounts are right-of-way payments, estimated to be approximately $2 million per year, related to cancellable gas storage lease payments that are reasonably likely to occur over the remaining life of all storage reservoirs, which have been assumed to be 65 years.

The Company and certain affiliates, in aggregate, have access to $500 million of letters of credit that they can issue. The total outstanding letters of credit that related to the Company as at December 31, 2017 was $6 million.

ENVIRONMENTAL

The Company subject to various federal, state and local laws relating to the protection of the environment. These laws and regulations can change from time to time, imposing new obligations on the Company.

Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and the Company and its affiliates are, at times, subject to environmental remediation at various contaminated sites. The Company manages this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that the Company is unable to recover payment for environmental liabilities from insurance or other potentially responsible parties, the Company will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of the Company.

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.

In its fiscal 2003 Rate Case, the Company sought OEB approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with a then current MGP claim and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2017 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.

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 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, 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 16, 2018 should be read in conjunction with the audited Consolidated Financial Statements and notes thereto of Enbridge Gas Distribution Inc. (the Company, we, our or us) as at and for the year ended December 31, 2017, which are prepared in accordance with generally accepted accounting principles 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, 2016. 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.

In 2014, Canadian securities regulators approved the extension of the Company's exemptive relief to continue reporting under U.S. GAAP instead of International Financial Reporting Standards (IFRS) until the earlier of January 1, 2019, and the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation. The Company is in the process of obtaining further extension of this exemptive relief beyond January 1, 2019.

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; the expected sale of St. Lawrence Gas Company Inc. (St. Lawrence Gas); and the proposed amalgamation with Union Gas Limited (Union Gas).

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

The Company's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law and tax rate increases, exchange rates, interest rates, natural gas prices and supply of 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 represents earnings attributable to the common shareholder adjusted for weather and other items. Prior to January 2017, the impacts of warmer/(colder) than normal weather were removed for the purpose of calculating adjusted earnings. Effective January 1, 2017, the Company no longer makes such an adjustment to its adjusted earnings. 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. 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 approximately 170 years. The Company serves approximately 2.2 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. In August 2017, the Company entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas. The transaction is expected to close in 2018, subject to regulatory approval and certain pre-closing conditions. 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

To achieve the Company's vision to deliver the energy Ontario needs, we are focused on delivering strategic priorities that maximize the value of our core business. These priorities include operating and maintaining the existing storage, transmission and distribution system safely and reliably, attaching new customers, renewing the existing system as needed and positioning the business for future growth with new services and assets.

Each year, we add over 30,000 customers and deploy capital in excess of $400 million to maintain and grow our assets. We expect customer growth to remain strong, driven by Ontario population growth and demand for natural gas as a cost effective source of energy. We will continue to develop opportunities to support a lower carbon future in Ontario, including expanding generation and capture of Renewable, Natural Gas (RNG), increasing the use of Compressed Natural Gas (CNG) in transportation and integration of gas and electric infrastructures.

We, together with Union Gas, applied to the OEB to amalgamate on January 1, 2019 - a development that would create the single largest natural gas utility in North America in terms of send-out volumes, and third largest in terms of customers. This harmonization would drive efficiencies and synergies, leverage greater supply-chain strength, create new opportunities for growth, and form a stronger platform to deliver strong, predictable returns to shareholders and superior value and service to customers.

PERFORMANCE OVERVIEW

Year ended December 31,	**2017**	2016
(millions of dollars, except per share amounts)		
Earnings attributable to the common shareholder[1]	**248**	228
Cash flow data		
Cash provided by operating activities	**564**	642
Cash used in investing activities	**(800)**	(740)
Cash provided by financing activities	**252**	93
Dividends		
Common share dividends declared	**600**	237
Dividends declared per common share	**2.90**	1.36
Preference share dividends declared	**2**	2
Dividends declared per preference share	**0.58**	0.54
Total revenues		
Gas commodity and distribution revenues	**2,760**	2,437
Transportation of gas for customers	**418**	330
Other revenue	**114**	100
Total revenues	**3,292**	2,867
Total assets	**11,013**	10,222
Total long-term liabilities	**5,902**	5,223

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

HIGHLIGHTS

Year ended December 31,	**2017**	2016
Number of active customers[1] *(thousands)*	**2,190**	2,158
Heating degree days[2]		
Actual	**3,499**	3,412
Forecast based on normal weather	**3,639**	3,617
Actual heating degree days below forecasted	**(140)**	(205)
Warmer than normal weather[3] *(millions of dollars)*	**15**	18
Volumetric statistics *(millions of cubic metres)*		
Gas commodity sales	**7,818**	7,245
Transportation of gas for customers	**4,008**	4,076
Unbundled volumes[4]	**99**	392
Total volumes	**11,925**	11,713

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 (GTA).
3 Gas distribution margin impact of warmer than normal weather.
4 Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.

EFFECT OF WEATHER

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 heating degree day forecast for the 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.

EARNINGS

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings attributable to the common shareholder	**248**	228
Warmer than normal weather (after-tax impact)	**—**	13
Loss on settlement of pre-issuance hedge contracts	**—**	2
Adjusted earnings[1]	**248**	243

1 Earnings attributable to the common shareholder for each period includes the impact of warmer than normal weather in the Company's franchise areas. Prior to January 1, 2017, the impacts of warmer than normal weather were removed for the purpose of calculating the Company's adjusted earnings. Effective January 1, 2017, the Company no longer makes such an adjustment to its adjusted earnings. The after-tax impact of warmer than normal weather for the year ended December 31, 2017 was $11 million. For more information on the non-GAAP measures see page 2.

Earnings attributable to the common shareholder were $248 million for the year ended December 31, 2017 compared with $228 million for the year ended December 31, 2016. The increase primarily resulted from higher distribution charges and lower employee severance costs. This was partially offset by higher earnings sharing in 2017.

In addition to these drivers, adjusted earnings for the year ended December 31, 2017 were comparably lower to the same period in 2016 due to the exclusion of the effect of warmer than normal weather for adjusted earnings purposes as noted above.

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 related debt's interest costs. The gains or losses will be amortized back into adjusted earnings over the term of the related debt.

REVENUES

Revenues for the year ended December 31, 2017 were $3,292 million compared with $2,867 million for the year ended December 31, 2016. The increase in revenues was primarily due to amounts billed to customers to recover cap and trade compliance costs through rates beginning January 1, 2017, higher sales volumes and higher natural gas prices. This was partially offset by the settlement of regulatory balances.

RECENT DEVELOPMENTS

2018 RATE APPLICATION

The Company's final rate order for the setting of rates for 2018 was approved by the OEB in December 2017. The 2018 rate application was filed in August 2017 in accordance with the Company's approved customized IR plan, and represents the final year of a five-year term.

CAP AND TRADE COMPLIANCE PLAN

In November 2017, the Company filed its 2018 Cap and Trade Compliance Plan with the OEB. Subsequently, on November 30, 2017, the OEB issued a Decision and Order advising that final 2017 OEB-approved Cap and Trade rates shall continue until such time as the OEB completes its review and makes a determination of the approved 2018 Cap and Trade rates.

APPLICATION TO AMALGAMATE

In November 2017, the Company and Union Gas, an affiliate of the Company, (together, the Applicants) filed an application with the OEB to amalgamate, in accordance with the OEB's guidance for Mergers, Acquisitions, Amalgamations and Divestitures (MAAD), with an effective date of January 1, 2019. Under the OEB's MAAD policy, the Applicants are seeking to defer rate rebasing for ten years to allow the utilities to identify and leverage best practices and implement integrated solutions. This filing initiated the regulatory review process which will continue through 2018 with a decision from the OEB expected in the second half of 2018.

Subsequent to the above application, also in November 2017, the Company and Union Gas submitted a second, related, application. The application seeks an order approving a rate setting mechanism for the ten year rebasing period effective January 1, 2019 that would apply if Enbridge proceeds with the amalgamation of the Company and Union Gas. The Applicants are seeking approval of a price cap mechanism which includes an annual rate escalation at inflation; continues to pass through certain costs; allows for pass through of capital expenditures in excess of an OEB approved threshold; and allows for non-routine adjustments with a materiality threshold of $1 million.

The final decision on whether to proceed with the amalgamation is subject to the completion of the regulatory process and the Company, Union Gas, and Enbridge's review and assessment of the regulatory outcomes and their respective Board of Directors approvals.

SALE OF ST. LAWRENCE GAS

In August 2017, the Company entered into an agreement to sell the issued and outstanding shares of its wholly-owned subsidiary, St. Lawrence Gas, for cash of approximately $88 million (US $70 million), minus third-party debt at closing and subject to customary working capital adjustments. The transaction is subject to regulatory approval and certain pre-closing conditions, and is expected to close in 2018. As at December 31, 2017, St. Lawrence Gas was classified as held for sale on the Consolidated Statements of Financial Position and was measured at the lower of its carrying value and fair value less costs to sell.

PRECEDENT AGREEMENT FOR LONG-TERM TRANSPORTATION CAPACITY

As part of the Company's 2018 Gas Supply Plan, approved by the OEB, the Company will be contracting for approximately 116,000 10^6m^3/day of transportation from NEXUS Gas Transmission, LLC (NEXUS), an affiliated company under common control, and has executed a Service Agreement. NEXUS advised the Company on September 1, 2017, that it had received all governmental approvals and had filed with the Federal Energy Regulatory Commission (FERC) its acceptance of the certificates issued to NEXUS as part of the Certificate Order. Motions were subsequently received by FERC to stay the Certificate which were denied in January 2018. A motion from the City of Green to stay construction over Water Quality Certificate concerns has been granted by the U.S. Court of Appeals and will be reviewed at the end of January 2018. The NEXUS in-service date continues to be estimated for the third quarter of 2018.

In March 2017, the Company signed a precedent agreement and financial assurance agreement with TransCanada Pipelines Limited (TransCanada) for incremental pipeline transportation capacity from Parkway (GTA) to the Company's franchise areas. Concurrently, the Company signed a precedent agreement with Union Gas, for pipeline transportation capacity from the Dawn trading hub to GTA. All related transportation agreements have a 15-year term and are targeted to start in November 2019. The agreements are required to meet growth in customer demand and continue 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 October 2013 TransCanada Mainline Settlement Agreement signed between the Company, TransCanada, Union Gas and Énergir, L.P. (formerly known as Gaz Métro Limited Partnership).

APPOINTMENT OF NEW OFFICERS

Effective February 27, 2017, Mr. James Sanders was appointed as President of the Company. At the same time, Ms. Cynthia Hansen, the Company's previous President, was appointed as Executive Chair of the Company.

Effective August 3, 2017, Ms. Wendy Zelond was appointed as Vice President, Finance of the Company.

RESULTS OF OPERATIONS

Year ended December 31,	**2017**	2016
(millions of dollars)		
Gas commodity and distribution revenue	**2,760**	2,437
Transportation of gas for customers	**418**	330
Gas commodity and distribution costs	**(2,032)**	(1,636)
Gas distribution margin[1]	**1,146**	1,131
Other revenue	**114**	100
Operating and administrative expenses	**(520)**	(534)
Depreciation and amortization	**(330)**	(322)
Earnings sharing	**(24)**	(3)
Other income	**64**	73
Interest expense, net	**(214)**	(206)
Income taxes	**14**	(9)
Earnings	**250**	230
Earnings attributable to the common shareholder	**248**	228

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

GAS DISTRIBUTION MARGIN

Gas distribution margin for the year ended December 31, 2017 increased by $15 million compared with the year ended December 31, 2016. The increase primarily resulted from higher distribution charges, net of incremental amounts recovered through the Rate 332 Tariff in 2017 which is reflected in Other Revenue. This was partially offset by the settlement of regulatory balances.

The heating degree days reported in 2017 were 140 days warmer compared with forecast heating degree days. On a weather-normalized basis, gas distribution margin for the year ended December 31, 2017 would have been higher by $15 million (2016 - higher by $18 million). Weather, measured in heating degree days, was 3,499 heating degree days for the year ended December 31, 2017 compared with 3,412 heating degree days for the year ended December 31, 2016.

The following is an analysis of other individual line items in the Consolidated Statements of Earnings which may, or may not, materially impact earnings due to the nature of rate regulation, as certain items could be reflected or offset in the revenues described above.

OTHER REVENUE

Other revenue for the year ended December 31, 2017 increased by $14 million compared with the year ended December 31, 2016. The increase primarily resulted from higher transportation revenues under the Rate 332 Tariff, which began in late 2016.

OPERATING AND ADMINISTRATIVE

Operating and administrative expenses for the year ended December 31, 2017 decreased by $14 million compared with the year ended December 31, 2016. The decrease primarily resulted from lower employee related costs, including severance costs due to workforce reductions in October 2016, lower pension costs and the settlement of regulatory balances. This was partially offset by increased Demand Side Management (DSM) program costs.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the year ended December 31, 2017 increased by $8 million compared with the year ended December 31, 2016. The increase primarily resulted from a higher overall asset base, mainly due to the Work and Asset Management Solution (WAMS) and GTA Project which were each placed into service during 2016.

EARNINGS SHARING

Earnings sharing represents the customer portion of regulated weather normalized earnings in excess of the approved return on equity threshold applicable to the Company. Earnings sharing will result in the return of revenue of $24 million to customers for the year ended December 31, 2017, subject to OEB approval, compared to $3 million in 2016.

OTHER INCOME

Other income for the year ended December 31, 2017 decreased by $9 million compared with the year ended December 31, 2016. The decrease primarily resulted from a non-taxable reimbursement of Part VI.1 tax from Enbridge in 2016 and lower interest income on cash balances.

INTEREST EXPENSE

Interest expense, net, for the year ended December 31, 2017 increased by $8 million compared with the year ended December 31, 2016. The increase primarily resulted from lower capitalized interest from decreased spending on the GTA project, which was placed into service in March 2016. This was partially offset by a loss on the settlement of pre-issuance hedge contracts in August 2016.

INCOME TAXES

Year ended December 31,	**2017**	2016
(millions of dollars)		
Earnings before income taxes	**236**	239
Income taxes	**(14)**	9
Effective tax rate (%)	**(5.9)**	3.8

The effective tax rate for the year ended December 31, 2017 was lower compared with the year ended December 31, 2016. The decrease primarily resulted from higher post-retirement benefit contributions and temporary differences related to regulatory property, plant and equipment and intangible assets, partially offset by the effects of investments in foreign subsidiaries held for sale and a decrease in Part VI.1 tax, net of Part I tax, relative to lower pre-tax earnings.

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 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, 2017. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

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, 2017.

		December 31, 2017			December 31, 2016
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of dollars)					
Enbridge Gas Distribution Inc.	2019	**1,000**	**960**	**40**	1,000
St. Lawrence Gas Company, Inc.	2019	**16**	**12**	**4**	17
Total credit facilities		**1,016**	**972**	**44**	1,017

1 *Includes facility draws and commercial paper issuances, net of discount, that are back-stopped by the external credit facility. St. Lawrence Gas draws are shown as Liabilities held for sale, current and long-term on the Consolidated Statements of Financial Position.*

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

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

As at December 31, 2017, the Company had a negative working capital of $289 million. Despite the negative working capital, the Company's liquidity is sourced from cash flows from operations, access to funds from credit facilities, short-term borrowings and, if necessary, through intercompany borrowings. In addition, the Company has access to additional sources of funding from Enbridge. At December 31, 2017, the net available liquidity totaled $60 million (2016 - $661 million).

The Company must adhere to covenants in its 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, 2017, the Company was in compliance with all covenants.

OPERATING ACTIVITIES

Cash provided by operating activities was $564 million for the year ended December 31, 2017 compared to $642 million in 2016. The decrease in cash provided by operating activities primarily resulted from changes in working capital accounts due to timing of payments of Accounts payable and collections of Accounts receivables and higher employee pension plan contributions.

INVESTING ACTIVITIES

Cash used in investing activities was $800 million for the year ended December 31, 2017 compared to $740 million in 2016. The increase in cash used in investing activities was primarily due to additions to intangible assets in relation to the cap and trade regulation in order to meet greenhouse gas compliance obligations in the Province of Ontario. This was partially offset by lower comparative capital spend due to the GTA Project and WAMS program each being placed into service in 2016.

CAPITAL EXPENDITURES

Year ended December 31,	**2017**	2016
(millions of dollars)		
Growth enhancements	**190**	379
Maintenance capital	**272**	338
Total capital expenditures	**462**	717

The Company's existing distribution network consists of approximately 39,000 kilometers 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.

In 2018, the Company is expected to embark on $195 million of capital growth projects, including new construction, reinforcement, and expansion of our distribution system. The net planned liquidity, together with cash from operations, short-term borrowings 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 $252 million for the year ended December 31, 2017 compared to $93 million in 2016. The increase in cash provided by financing activities mainly resulted from higher short-term borrowings and proceeds from issuance of common shares. These were partially offset by higher common share dividends declared and repayments of maturing term notes.

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

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, 2017, 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	213,337,897

1 Outstanding share data information is provided as at February 16, 2018.

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.

In its fiscal 2003 Rate Case, the Company sought OEB approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with a then current MGP claim and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2017 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.

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 significant 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	2 years	3 years	4 years	5 years	After 5 years
(millions of dollars)							
Long-term debt[1]	3,780	—	—	400	175	—	3,205
Gas transportation and storage contracts[2]	4,604	996	763	550	480	433	1,382
Loans from affiliate company[1]	375	—	—	—	—	—	375
Customer care service	176	60	61	55	—	—	—
Right-of-way commitments[3]	130	2	2	2	2	2	120
Capital commitments	44	15	15	14	—	—	—
Pension contributions[4]	37	37	—	—	—	—	—
Total contractual obligations	9,146	1,110	841	1,021	657	435	5,082

1 Excludes interest, discounts and premiums. Changes to the planned funding requirements are dependent on the terms of any debt re-financing agreements.
2 Includes the transportation agreement for long-term transportation capacity.
3 Right-of-way payments, estimated to be approximately $2 million per year, related to cancellable gas storage lease payments that are reasonably likely to occur for the remaining life of all storage reservoirs, which has been assumed to be 60 years for the purposes of calculating the amount of future minimum commitments beyond 2022.
4 The Company is unable to estimate retirement plan contributions beyond 2018 due primarily to uncertainties about market performance of plan assets.

The Company and certain affiliates, in aggregate, have access to $500 million of letters of credit that they can issue. The total outstanding letters of credit that related to the Company as at December 31, 2017 was $6 million.

QUARTERLY FINANCIAL INFORMATION[1]

	2017				2016			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
(millions of Canadian dollars)								
Revenues	**1,025**	**406**	**601**	**1,260**	811	342	594	1,120
Earnings attributable to the common shareholder[2]	**98**	**3**	**51**	**96**	61	4	49	114
Warmer/(colder) than normal weather (after-tax impact)	**(12)**	**—**	**2**	**21**	7	—	(7)	13
Loss on settlement of pre-issuance hedge contracts	**—**	**—**	**—**	**—**	—	2	—	—

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.

Beginning January 1, 2017, revenues include amounts billed to customers to recover cap and trade compliance costs through rates. Similar to the gas supply procurement framework, the OEB's framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates, subject to OEB approval.

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 varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather.

FOURTH QUARTER 2017 HIGHLIGHTS

Earnings attributable to the common shareholder were $98 million for the three months ended December 31, 2017 compared with $61 million for the same period in 2016. The increase primarily resulted from colder weather during the fourth quarter of 2017 compared to 2016, lower employee severance costs, lower depreciation expense and lower pension related costs. This was partially offset by higher earnings sharing in 2017 and higher DSM program costs.

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,	**2017**	2016
(millions of dollars)		
Enbridge Energy Distribution Inc.		
Common share dividends declared	**600**	237
Union Gas[1]		
Purchase of gas storage and transportation services	**112**	—
Revenue from unregulated storage capacity	**5**	—
IPL System Inc.		
Dividend income	**63**	63
Interest expense	**27**	27
Enbridge		
Purchase of treasury and other management services	**49**	49
Part VI.1 tax reimbursement	**—**	5
Tidal Energy Marketing Inc.		
Purchase of natural gas	**54**	24
Revenue from optimization services	**9**	8
Revenue from unregulated storage capacity	**2**	2
Tidal Energy Marketing (U.S.) LLC		
Purchase of natural gas	**56**	26
Aux Sable Canada LP		
Purchase of natural gas	**—**	16
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**30**	30
Other related entities		
Purchase of gas transportation services	**25**	31

1 On February 27, 2017, Enbridge and Spectra Energy Corp. (Spectra) combined, to complete a merger transaction. The Company purchases gas storage and transportation services from Union Gas, an indirectly wholly owned subsidiary of Spectra, at prevailing market prices and under normal trade terms. The purchase of gas storage and transportation services and revenue from unregulated storage capacity from Union Gas includes only 10 months of activity subsequent to the merger transaction.

The Company had related party balances as follows:

December 31,	2017	2016
(millions of dollars)		
Common share ownership from parent company		
Enbridge Energy Distribution Inc.	**2,417**	1,917
Dividend payable	**—**	59
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**9**	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	**30**	34
Other accounts receivable/(payable)		
Other related entities, net	**(40)**	(23)

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, 2017, the investment of $825 million (2016 - $825 million) in these shares resulted in a weighted average dividend yield of 7.6%.

At December 31, 2017, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.9% and $175 million at 7.5%). 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, 2017, interest paid amounted to $27 million (2016 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 1.1% 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.

Part VI.1 Tax Reimbursement
The Company entered into an agreement with Enbridge for the transfer of Part VI.1 tax and the related Part I tax deduction. The Company received a non-taxable reimbursement relating to the transfer.

Natural Gas Purchases
The Company 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 under normal trade terms. Contractual obligations under the Tidal Energy Marketing (U.S.) LLC and Tidal Energy Marketing Inc. contracts are 2018 to 2019 - $32 million, 2020 to 2021 - nil, and thereafter - nil.

Optimization Services
The Company provides pipeline and storage optimization services to Tidal Energy Marketing Inc., an affiliated entity under common control.

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 Storage and Transportation Services
The Company 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, Niagara Gas Transmission Limited, 2193914 Canada Limited and Union Gas. The Company also contracted for natural gas storage services from Union Gas. Contractual obligations under the Union Gas, Vector Pipeline Limited Partnership (U.S.) and Vector Pipeline Limited Partnership (Canadian) are 2018 to 2019 - $316 million, 2020 to 2021 - $280 million and thereafter - $358 million.

Unregulated Storage Services
On July 31, 2017, the Company entered into a Gas Storage Service Agreement (GSSA) with Union Gas, whereby Union Gas contracted all of the Company's unregulated storage space and deliverability effective September 2017.

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.

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

RISK FACTORS AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigating factors is 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 2017 as the Company's 2018 rate application was 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 return on equity (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 Gas). 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 Gas, 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 Gas 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.

MARKET RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in natural gas prices, emission allowance prices, foreign exchange rates and interest rates (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.

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 customers; therefore, the net exposure to the Company is zero.

Emission Allowance Price Risk

Emission allowance price risk is the risk of gain or loss due to changes in the market price of emission allowances that the Company is required to purchase for itself and most of its customers to meet greenhouse gas compliance obligations under the Ontario Cap and Trade framework. Similar to the gas supply procurement framework, the OEB's framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates, subject to OEB approval.

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 United States dollars (USD). As a result, the Company's earnings, cash flows, and OCI are exposed to fluctuations resulting from USD exchange rate variability.

The Company implemented a policy in 2016 to hedge a portion of USD denominated unregulated storage revenue exposures. Qualifying derivative instruments were used to hedge anticipated USD denominated revenues and to manage variability in cash flows through September 2017. During September 2017, the Company assigned its USD denominated unregulated storage contracts to Union Gas, an affiliated company under common control as a result of the merger transaction. The Company has also novated all of its qualifying derivative instruments relating to forward exchange contracts to Union Gas.

A portion of the Company's purchases of natural gas are denominated in USD and as a result there is exposure to fluctuations in the exchange rate of the USD 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 were used through January 2017 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 were used during 2016 to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances.

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.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the financial statement line item in the Consolidated Statements of Financial Position and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges or net investment hedges at December 31, 2017 or December 31, 2016.

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, 2017	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 dollars)					
Other long-term liabilities					
Foreign exchange contracts	—	—	—	—	—
Total net derivative liabilities					
Foreign exchange contracts	—	—	—	—	—

December 31, 2016	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 dollars)					
Other long-term liabilities					
Foreign exchange contracts	(1)	—	(1)	—	(1)
Total net derivative liabilities					
Foreign exchange contracts	(1)	—	(1)	—	(1)

The Company did not have any outstanding derivative instruments relating to interest rate contracts as at December 31, 2017. Derivative instruments relating to interest rate contracts as at December 31, 2016 had a notional principal of $8 million for interest rate contracts for short-term borrowings and zero for interest rate contracts on the anticipated issuance of long-term debt.

The Company did not have any outstanding derivative instruments relating to forward exchange contracts as at December 31, 2017. At December 31, 2016 the Company's derivative instruments relating to foreign exchange forward contracts matured through 2023 and had a notional principal of $13 million (US $10 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,	**2017**	2016
(millions of dollars)		
Amount of unrealized loss recognized in OCI Cash flow hedges		
Interest rate contracts	—	(13)
Foreign exchange contracts	—	(1)
	—	(14)
Amount of loss reclassified from AOCI to earnings *(effective portion)*		
Interest rate contracts[1]	**(4)**	(3)
	(4)	(3)
Amount of loss reclassified from AOCI to earnings *(ineffective portion)*		
Interest rate contracts[1]	—	(3)
	—	(3)

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

The Company estimates that no amount in AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on interest and foreign exchange rates in effect when derivative contracts that are currently outstanding mature.

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, draws under committed credit facilities and long-term debt, which includes debentures and medium term notes (MTNs) 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 also 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 as at December 31, 2017. As a result, all credit facilities are available to the Company and the banks are obligated to fund the Company under the terms of the facilities.

CREDIT RISK

Credit risk arises from the possibility that a counterparty will default on its contractual obligations. 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 obtained 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, which totaled $29 million at December 31, 2017 (December 31, 2016 - $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. 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 concentrations, with respect to derivative instruments, in the Canadian, United States, European, Asian or other financial institutions counterparty segments at December 31, 2017 or December 31, 2016.

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 are 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 FINANCIAL INSTRUMENTS

The Company categorizes its derivative instruments 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 a 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, foreign exchange, 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, 2017, the Company had Level 2 derivative assets with fair value of nil (2016 - nil) and Level 2 derivative liabilities with fair value of nil (2016 - $1 million). The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers between levels as at December 31, 2017 or December 31, 2016.

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, 2017, the fair value of the investment was $825 million (2016 - $825 million). The fair value of the Company's investment is classified as a Level 2 measurement and as at December 31, 2017 and 2016 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, 2017, the Company's long-term debt, including the current portion had a carrying value of $3,780 million (2016 - $3,983 million) before debt issue costs and a fair value of $4,363 million (2016 - $4,585 million).

The fair value of other financial assets and liabilities other than derivative instruments and long-term debt approximate their cost due to the short period to maturity.

GENERAL BUSINESS RISKS
Service Interruption
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 and a strong distribution system. 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 interruption. The Company procures supply, storage 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, reducing the potential for supply disruption. Network analysis, interruptible customers and the curtailment process enable the Company to manage gas supply deliveries to customers when required. The GTA Project has now been placed in service and is a key mitigation, providing significant diversification of gas supply to the Company's distribution network and further reducing the likelihood of a service interruption incident. Additional mitigations to any service interruption to the distribution system are discussed in the Operating Risk section below.

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.

Other examples of 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 a comprehensive damage prevention program along with leak surveys, corrosion surveys 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 conducts periodic planned emergency response exercises and training. 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.

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.

Environmental, Health and Safety Risk

The Company's workers, operations, facilities are subject to municipal, provincial and federal legislation which regulate the protection of the environment and the health and safety of workers. For the environment, primarily this includes the regulation of discharges to air, land and water; the management and disposal of solid and hazardous waste, and contaminated soil and groundwater; and the assessment of contaminated sites.

The operation of the Company's gas distribution system and gas facilities comes with risk of incidents, abnormal operating conditions or other unplanned events that could result in spills or emissions to the environment that could exceed permitted levels. These events could result in injuries to workers or the public, fines, penalties, adverse impacts to the environment in which we operate within, and/or property damage. The Company could also incur future liability for environmental (soil and groundwater) contamination associated with past and present site activities.

In addition to the operation of the gas distribution system, the Company also operates unregulated operations including small oil and brine production and storage facilities in southwestern Ontario. Environmental risk associated with these facilities is the possibility of spills, releases or leaks. In the event of an incident (spill), remediation of the affected area would be required. There would also be potential for fines, orders or charges under environmental legislation, and potential third-party liability claims by affected land owners.

The gas distribution system and other Company operations must maintain a number of environmental approvals and permits from governmental authorities to operate. As a result, these facilities and the distribution network are subject to periodic inspection. An Annual Written Summary Report is submitted to the Ontario Ministry of Environment and Climate Change (MOECC) to demonstrate the Company is in good standing related to its Environmental Compliance Approvals. Failure to maintain regulatory compliance could result in operational interruptions, fines, penalties, and/or orders for additional pollution control technology or environmental remediation, etc. As environmental requirements and regulations become more stringent, the cost to maintain compliance and the time required to obtain approvals has consistently increased.

Ontario commenced a cap and trade system on January 1, 2017. Under the cap and trade regulation, the Company is required to purchase emission allowances for most of its customers' use of natural gas as well as for emissions from its own operations. This process is complex and requires ongoing monitoring of the carbon market and related climate change and carbon policies not only in Ontario but also in other newly linked jurisdictions as of January 1, 2018 - namely California and Quebec. This linkage which has been enabled in Ontario with various greenhouse gas reporting and cap and trade regulation amendments over the course of 2017 will create a larger and more liquid market for carbon allowances, which may help to mitigate compliance costs for the Company's customers in this compliance period. However, non-compliance or unexpected policy changes may cause significant changes to the cost of maintaining compliance and needs to be closely monitored to ensure impacts are understood. For example, if the price of a carbon allowance goes up significantly because of a policy change in California, the cost of natural gas goes up and in turn, the demand for the product may decline.

The Company submitted and received supportive endorsement of its 2017 Compliance Plan, and is in the process of defending its filed 2018 Compliance Plan. Further, the Company is obliged to file a 2019/2020 Compliance Plan as well as an Annual Report summarizing 2017 results by August 1, 2018 to meet the OEB's Cap and Trade Framework Requirements. The Compliance Plans detail how the Company will meet its carbon compliance obligation through carbon allowance and/or offset procurement as well as through customer and facility abatement projects that may be deemed cost effective. By creating a prudent and thoughtful plan and executing with excellence, the company best mitigates any risk of cost disallowance. The OEB approved use of the 2017 final rate for recovery of 2018 cap and trade compliance costs until determined otherwise.

As with previous years, in 2017 the Company reported 2016 GHG emissions to the Ontario Ministry of Environmental and Climate Change, Environment and Climate Change Canada, and a number of voluntary reporting programs. Emissions from the Company's Ontario combustion sources were verified in detail by a third party accredited verifier with no material discrepancies found. Additionally, operational emissions from venting, fugitive and natural gas distribution emissions were reported to the MOECC for the first time in 2017 in accordance with O. Reg. 143/16 - Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulation standard quantification methods ON.350 and ON.400, respectively. The Company continues to monitor developments and attend stakeholder consultations in Ontario.

The Company utilizes an emissions data management system to help with the data capture and mandatory and voluntary reporting needs of the Company. Quantification methodologies and emission factors will continually be updated in the system as required. The Company publicly reports its GHG emissions and has developed internal procedures for more frequent monthly Cap and Trade related GHG reporting. The Company continues to work with industry associations to refine quantification methodologies and emissions factors, as well as best management practices to minimize emissions. The Company's plan to reduce emissions in 2018 is outlined in the Facility Abatement Plan within its Compliance Plan.

Public, Worker and Contractor Safety
The Company's distribution system is operated in close proximity 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 subject to personal safety risks.

Safety and operational reliability are the most important priorities at the Company. The Company's mitigation efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its integrated management system, asset management system and emergency response preparedness. The Company also actively engages stakeholders through public safety awareness activities to ensure the public is aware of potential hazards and understands the appropriate actions to take in the event of an emergency. The Company also actively engages first responders through education programs that endeavour to equip first responders with the skills and tools to safely and effectively respond to a potential incident.

Finally, the Company believes in a safety culture where safety incidents are not tolerated by employees and contractors and has established a target of zero incidents. For employees, safety objectives have been incorporated across all levels of the Company and are 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

There could be negative impacts of the Company's business, operations or financial results due to change in the Company's reputation with stakeholders, special interest groups (including non-governmental organizations), 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 business;
- loss of ability to secure growth opportunities;
- delay in project execution;
- legal action;
- increased regulatory oversight or delays in regulatory approval; and
- loss of ability to hire and retain top talent.

The Company is also exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on governments and regulators by special interest groups. Recent judicial decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums.

Information Technology Security or Systems Incident

The Company's business is dependent upon information systems and other digital technologies for controlling the Company's plants, processing transactions and summarizing and reporting results of operations. The secure processing, maintenance and transmission of information is critical to the Company's operations. A security breach of the Company's network or systems could result in improper operation of the Company's assets, potentially including delays in the delivery or availability of the Company's customers' products, contamination or degradation of the products the Company transport and store or distribute. Furthermore, the Company collects and stores sensitive data in the ordinary course of business, including personal identification information of employees as well as proprietary business information and that of customers, suppliers, investors and other stakeholders. The Company has a Cybersecurity controls framework in place which has been derived from the NIST Cybersecurity Framework and ISO 27001 standards. The Company monitors their controls effectiveness in an increasing threat landscape and continuously takes action to improve their security posture. The Company implemented a 7X24 security operations center to monitor, detect and investigate any anomalous network activity together with an incident response process that is teste on a monthly basis. The Company conducts independent cyber security audits and penetration tests on a regular basis to test that preventative and detective controls are working as designed. However, the Company does not maintain specialized insurance for possible liability resulting from a cyber-attack on the Company's assets.

Despite the Company's security measures, information systems may become the target of cyber-attacks or security breaches (including employee error, malfeasance or other breaches), which could compromise the Company's network or systems and result in the release or loss of the information stored therein, misappropriation of assets, disruption to operations or damage to the Company's facilities. As a result of a cyber-attack or security breach, the Company could also be liable under laws that protect the privacy of personal information, subject to regulatory penalties, experience damage to the Company's reputation or a loss of consumer confidence in the Company's products and services, or incur additional costs for remediation and modification or enhancement of information systems to prevent future occurrences, all of which could adversely affect the Company's business, operations or financial results.

Transformation Projects
Transformation project risk is the risk that modernization projects carried out by Enbridge and its subsidiaries do not fully deliver planned results due to insufficiently addressing the risks associated with project execution and change management. This could result in negative financial, operational and reputational impacts. Enbridge launched projects in 2016 to transform various processes, capabilities and reporting systems infrastructure to continuously improve effectiveness and efficiency across the organization. To monitor and mitigate project risk, Enbridge established an enterprise-wide approach to manage project the planning and authorization, implement progress tracking, risk controls and mitigating strategies for risk.

CRITICAL ACCOUNTING ESTIMATES

The Company’s consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States, which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. The Company’s most critical accounting policies and estimates discussed below have an impact across the various segments of the Company's business.

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, 2017 of $7,532 million (2016 - $7,418 million), or 68% of total assets (2016 - 72%), 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, 2017, the Company's regulatory assets totaled $728 million (2016 - $634 million) and regulatory liabilities totaled $687 million (2016 - $720 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 $44 million higher than the expected return on plan assets for the year ended December 31, 2017 (2016 - $13 million higher) as disclosed in Note 16 to the 2017 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.

A 1% point change in the assumed health care cost trend rate would have the following effects for the year ended and as at December 31, 2017:

	1% Point Increase	1% Point Decrease
(in millions of dollars)		
Effect on total service and interest costs	—	—
Effect on accumulated postretirement benefit obligation	14	(11)

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 19 of the 2017 Consolidated Financial Statements.

REGULATORY GOVERNANCE

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

ADOPTION OF NEW STANDARDS

Clarifying the Definition of a Business in an Acquisition
Effective January 1, 2017, the Company early adopted ASU 2017-01 on a prospective basis. The new standard was issued with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses. This accounting update was applied to acquisitions and dispositions that occurred in the year.

Accounting for Intra-Entity Asset Transfers
Effective January 1, 2017, the Company early adopted ASU 2016-16 on a modified retrospective basis. The new standard was issued with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting
Effective January 1, 2017, the Company adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Improvements to Accounting for Hedging Activities
ASU 2017-12 was issued in August 2017 with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The accounting update allows cash flow hedging of contractually specified components in financial and non-financial items. Under the new guidance, hedge ineffectiveness is no longer required to be measured and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The ASU also allows the initial quantitative hedge effectiveness assessment to be performed at any time before the end of the quarter in which the hedge is designated. After initial quantitative testing is performed, an ongoing qualitative effectiveness assessment is permitted. The accounting update is effective January 1, 2019, with early adoption permitted, and is to be applied on a

modified retrospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation
ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans
ASU 2017-07 was issued in March 2017 primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. In addition, only the service cost component of net benefit cost is eligible for capitalization. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis for the statement of earnings presentation component and a prospective basis for the capitalization component. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets
ASU 2017-05 was issued in February 2017 with the intent of clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The ASU clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The accounting update is effective January 1, 2018 and will be applied on a modified retrospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the consolidated financial statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows
ASU 2016-18 was issued in November 2016 with the intent to clarify guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows. The accounting update requires that changes in restricted cash and restricted cash equivalents be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. The Company currently presents the changes in restricted cash and restricted cash equivalents under operating activities in the Consolidated Statement of Cash Flows. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company will amend the presentation in the Consolidated Statement of Cash Flows to include restricted cash and restricted cash equivalents with cash and cash equivalents and retrospectively reclassify all periods presented.

Simplifying Cash Flow Classification
ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statement of Cash Flows. The new guidance addresses eight specific presentation issues. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. The Company has assessed each of the eight specific presentation issues and the adoption of this ASU does not have a material impact on the consolidated financial statements.

Accounting for Credit Losses
ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to

extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on the Company's consolidated financial statements. The accounting update is effective January 1, 2020.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. The Company is currently gathering a complete inventory of its lease contracts in order to assess the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018 and is to be applied using a modified retrospective approach.

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. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative and are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial instruments for disclosure purposes is measured using exit price. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. The Company does not expect the adoption of this accounting update to have a material impact on the Company's consolidated financial statements.

Revenue from Contracts with Customers
ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the present standards in addition to additional disclosures. The new standard is effective January 1, 2018. The new standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company has decided to adopt the new standard using the modified retrospective method.

The Company has reviewed its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on the Company’s assessment, the application of the standard will result in a change in presentation for payments to customers under an earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments will be reflected as a reduction of revenue. The Company does not expect that these changes will have a material impact on revenue or earnings. The Company has also developed and tested processes to generate the disclosures which will be required under the new standard commencing in Q1 2018.