ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 1

Reference: Exhibit B, Tab 1, pages 3-4

Question:

The evidence indicates that the application was guided by the OEB's Handbook to Electricity Distributor and Transmitter Consolidations ("Consolidation Handbook").

a) Did Union and/or EGD consult with the Board or Board Staff about the applicability of the Consolidation Handbook to their proposed merger?

b) If yes, please provide all written documentation related to this consultation and the date of any meetings between the Board and/or Board Staff and the utilities.

c) If no, why did the utilities not seek guidance from the Board?

Response

a) EGD and Union have regular, informal discussions with the Board staff to keep each other current on regulatory matters. EGD and Union met with Board staff as well as the OEB Chair and General Counsel prior to filing specifically to inform them of the intent to file an amalgamation application. The discussions centered on gaining understanding of the MAADs framework and the associated filing requirements. These discussions did not reveal any impediment or restriction applicable to the planned amalgamation filing.

b) The meetings took place in July, August, September, October and November. There is no written documentation.

c) Please see part (a)

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 1

Reference: Exhibit B, Tab 1, page 4

Question:

a) Please provide the utilities definition of the "no harm test".
b) In the opinion of the utilities, does the no harm test deal with potential impacts on rates of one or both of the merging utilities?
c) The applicants have provided an estimated cumulative benefit to customers of amalgamation of $410 million over the proposed ten-year deferral period. How does this figure relate to the no harm test?

Response

a) As indicated at Exhibit B, Tab 1 page 18:

> "*The no harm test considers whether the proposed transaction will have an adverse effect on the attainment of the OEB's statutory objectives; where a proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application.*"
> (EB-2016-0351)

b) The no harm test is evaluated against the Board's statutory objectives. The statutory objectives for natural gas distributors are set out in section 2 of the *OEB Act, 1998.* The second statutory objective for gas is to protect the interests of consumers with respect to price and the reliability and quality of gas service.

c) The cumulative benefit to customers of $410 million is derived by comparing the annual revenue requirement for EGD and Union were they to continue operate on a standalone basis to the proposed revenue of Amalco operating under a price cap over the deferred rebasing period.

   Since customers are better off by $410 million as a result of the amalgamation the no harm test is satisfied.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, pages 18-19

Question:

a) For each of the statutory objectives shown, please indicate how the proposed amalgamation impacts the objective.
b) For each of the statutory objectives show, please indicate how they would be impacted if the amalgamation did not take place.

Response

a-b)

Please see the response to CCC Interrogatory #2(a) found at Exhibit C.CCC.2.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, pages 20-23

Question:

a) Please provide the revenue requirement for each of the years shown in Table 3 for each of Union, EGD and Amalco, broken down into its major components – OM&A, cost of debt, return on equity, depreciation, income taxes and other (if applicable).

b) Please provide all the assumptions used in calculating the revenue requirement figures shown in Table 3 for each year shown for each of Union, EGD and Amalco.

c) Please provide the current projections for the revenue requirement for 2018 for each of Union and EGD broken down in the same level of detail as requested in part (a) above.

d) Please provide a breakdown of the forecasted ratepayer benefits for each of the years shown in Table 3 between Union and EGD.

e) Do the figures for Union and EGD reflect any reductions in OM&A or capital costs resulting from the utilities operating as affiliates? If not, why not? If yes, please indicate the amount of savings included in each year

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Response

a) Please see the response to FRPO Interrogatory #11(a) found at Exhibit C.FRPO.11. For EGD and Union Gas stand-alone, refer to table 2 and 6. For Amalco, refer to table 9, 10 and 11.

b) Please see the response to FRPO Interrogatory #11(a) at Exhibit C.FRPO.11.

c) The 2018 revenue requirement that underpins the MAADs analysis was based on preliminary estimates for both utilities and does not reflect the 2018 Board-approved amount. For 2018, EGD is under a Custom IR and Union is under a Price Cap. Please see Table A for the EGD revenue requirement calculation.

Table A – Enbridge Gas Distribution

EGD 2018 preliminary Allowed Revenue

$ Millions	2018
Cost of Capital	
Rate base	6,246
Required rate of return	6.23%
	389
Cost of Service	
Gas costs	-
Operation and maintenance	468
Depreciation and amortization	305
Fixed financing costs	2
Municipal and other taxes	50
	826
Other Revenues	(43)
Income Taxes	55
Sub-total revenue requirement	1,228
Customer Care rate smoothing V/A adjustment	5
Allowed revenue	**1,233**

Table B – Union

$ Millions	2018
Forecasted Revenue (Price Cap)	**1,161**

As Union is under a Price Cap, Union cannot provide the information in a format similar to the one requested in part a). Please see the response to SEC Interrogatory#19 found at Exhibit C.SEC 19 for Utility costs and revenue.

d) Please see the response to CCC Interrogatory #2(c) found at Exhibit C.CCC.2.

e) The figures for Union and EGD do not reflect any costs from the utilities operating as affiliates. Union Gas and EGD have established intercompany service agreements (ISA) and are complying with the Affiliate Relationship Code (ARC) requirements. Wherestaff from each utility provides services to the affiliate, the fully allocated cost of that service will be charged/transferred to the affiliate. These costs are not forecasted or included at this time because each utility does not know how much work of this type will be performed in 2018.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, page 21

Question:

a) Custom IR frameworks can take many forms. Please provide the form of the Custom IR that would be proposed by each of Union and EGD in the absence of the amalgamation. Please fully explain all assumption used in the specific Custom IR frameworks.

b) Do the Custom IR frameworks for the 2020 to 2024 and 2026 to 2028 periods include a price cap mechanism for the non-rebasing years?

c) If yes, are the I and X factors the same as those for Amalco for each of the relevant years? If not, please explain fully.

d) Please provide the asset management plans referenced in the evidenced and used in the determination of the revenue requirements in Table 3.

Response

a) The form of Custom IR that would be proposed by each of Union and EGD in the absence of amalgamation would be similar to EGD's current Custom IR plan as approved by the Board in EB-2012-0459.

b) See answer to part a)

c) n/a

d) Please see the response to Board Staff Interrogatory#54(a) found at Exhibit C.STAFF.54.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, page 22

Question:
a) Please provide a version of Table 3 if the inflation rate used is 2.5% in place of the 1.73% used.
b) Did Union and EGD do any sensitivity analysis with respect to the projected $410 million in cumulative ratepayer savings? If yes, please provide details. If no, please explain why not.

Response

a) The applicant is unable to provide this sensitivity analysis as changing the inflation rate will have an impact on all key parameters underlying the MAADs analysis, and will require the utilities to recast all the assumptions.

b) No sensitivities were prepared in relation to the no harm test. The only sensitivities prepared for management are those that appear in the Board of Directors package, dated October 31, 2017. Please see Attachment 1 to the response to FRPO Interrogatory #1 found at Exhibit C.FRPO.1.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, pages 23-24

Question:
With respect to the potential risks to be faced by Amalco noted on pages 23 and 24 (interest rates, government policy, lower carbon economy, etc.), please explain how these risks are different than they would be for Union and/or EGD in the absence of the amalgamation.

Response

The risks noted at Exhibit B, Tab 1, pages 23 to 24 are the same types as those that would be faced by Union and/or EGD in the absence of the amalgamation. Please also see the response to SEC Interrogatory #10 found at Exhibit C.SEC.10.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, page 24

Question:
When available, please provide the 2017 financial statements for EGD and the 2017 annual report for Union.

Response

Please refer to Attachment 1 and Attachment 2.

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

(millions of dollars)	Preference Shares *(Note 11)*	Common Shares *(Note 11)*	Additional Paid-in Capital	Retained Earnings/ (Deficit)	Accumulated Other Comprehensive Loss *(Note 13)*	Total
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)	(Signed)
James Sanders	**David G. Unruh**
President	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:

		December 31,	
Asset Category	Target Allocation	**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.

ANNUAL REPORT 2017

An Enbridge Company

uniongas
An Enbridge Company

Stephen W. Baker
President

February 16, 2018

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited (Union Gas) 2017 Annual Report. It contains Union Gas' Management's Discussion and Analysis (MD&A), Management Responsibility for Financial Reporting, Financial Statements, and Corporate Directory. I invite you to visit www.sedar.com for electronic versions of Union Gas' Financial Statements, MD&A, and other filings throughout the year.

Stephen W. Baker
President

INTRODUCTION

The terms "we," "our," "us," "Union Gas" and "the Company" as used in this report refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas.

This Management's Discussion and Analysis (MD&A) dated February 16, 2018 for the twelve months ended December 31, 2017, should be read in conjunction with the audited Financial Statements and accompanying notes. The results reported herein have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and are presented in millions of Canadian dollars, except where noted. Additional information relating to us, including our most recent Annual Information Form, can be found at www.sedar.com.

In 2014, Canadian securities regulators approved the extension of our 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.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide readers with information about Union Gas, including management's assessment of Union Gas' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are based on management's intentions, plans, expectations, beliefs and assumptions about future events. These forward-looking statements are typically identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, likely, plan, project, predict, will, potential, forecast, target and similar words suggesting future outcomes or statements regarding an outlook. Although Union Gas believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and the 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. Material assumptions used to develop these forward-looking statements include assumptions about: the supply and demand for natural gas; prices of natural gas; inflation; interest rates; the results and costs of financing efforts; expected future cash flows; expected earnings (losses); expected costs related to projects under construction; expected capital expenditures; estimated future dividends; expected costs related to remediation and potential insurance recoveries; the availability and price of labour and construction materials; operational reliability; the ability to successfully complete merger, acquisition or divestiture plans; anticipated in-service dates and weather.

Forward-looking statements are subject to risks, uncertainties and other factors, many of which are outside our control and could cause actual results to differ materially from the results expressed or implied by those forward-looking statements. 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 Union Gas' future course of action depends on management's assessment of all information available at the relevant time. Factors used to develop these forward-looking statements and that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- local, provincial and federal legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of storms;

- the timing and extent of changes in commodity prices, interest rates and exchange rates;
- general economic conditions, including the risk of a prolonged economic slowdown or decline, or the risk of delay in a recovery, which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- changes in tax law and tax rate increases;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favourable terms, which can be affected by various factors, including credit ratings and general market and economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop pipeline, storage, and other related infrastructure projects and the effects of competition;
- the performance of natural gas storage, transmission and distribution facilities;
- sensitivity to variances in the commodity measurement process;
- the extent of success in connecting new natural gas supplies to Ontario transmission systems and in connecting to expanding gas markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by these forward-looking statements; and
- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements made in this document or otherwise, whether as a result of new information, future events or otherwise, except as required by applicable securities law. All subsequent forward-looking statements, whether written or oral, attributable to Union Gas or persons acting on Union Gas' behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to operating margin, which represents Gas sales and distribution revenue and Storage and transportation revenue less Gas commodity, storage and transportation costs. Management believes that the presentation of this measure provides useful information to investors and shareholders as it provides increased transparency and predictive value. Operating margin is not a measure that has standardized meaning prescribed by U.S. GAAP and is not considered an U.S. GAAP measure; therefore, this measure may not be comparable with similar measures presented by other issuers.

GENERAL

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with over 100 years of experience and service to customers. The distribution business serves about 1.5 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' storage and transmission business offers a variety of storage and transportation services to customers at the Dawn Hub (Dawn), the largest integrated underground storage facility in Canada and one of the largest in North America. As of November 1, 2017, after the completion of the 2017 Dawn to Parkway expansion, Union Gas' transmission system has an effective peak daily demand capacity of 7.5 billion cubic feet per day (Bcf/d), which increased from 7.2 Bcf/d in 2016.

Dawn offers customers an important link in the movement of natural gas from western Canadian and United States of America (U.S.) supply basins to markets in central Canada and the northeast U.S. Key pipeline interconnects in Canada and the U.S. have enabled us to deliver approximately 774 billion cubic feet (Bcf) of gas through our transmission system in 2017. The majority of Union Gas' annual transportation and storage revenue is generated by fixed demand charges. The average length of long-term transportation contracts is approximately 11 years, with the longest remaining transportation contract term being 15 years. The average length of long-term storage contracts is approximately five years, with the longest remaining storage contract term being 19 years.

As the supply of affordable natural gas in areas close to Ontario continues to grow, there is an increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the U.S. northeast. To secure the continued reliable delivery of natural gas and to serve a growing demand for clean, affordable natural gas, Union Gas has invested approximately $1.5 billion in capital projects between 2015 and 2017 to expand the Dawn-Parkway natural gas transmission system, and all facilities are now fully in service. This has increased the takeaway capacity from Dawn by approximately 20 percent or from 6.3 Bcf/d in 2014 to 7.5 Bcf/d in 2017.

Our distribution system consists of approximately 66,000 kilometres (km) of main and service pipelines. Our distribution pipelines carry natural gas from the point of local supply to customers. Our underground natural gas storage facilities have a working capacity of approximately 163 Bcf in 23 underground facilities located in depleted gas fields. The transmission system consists of approximately 4,900 km of high-pressure pipeline and five mainline compressor stations.

Union Gas' common shares are held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

On February 27, 2017 Enbridge Inc. (Enbridge) and Spectra Energy completed a stock-for-stock merger transaction (the Merger) pursuant to which Enbridge acquired all of the issued and outstanding common shares of Spectra Energy. As a result of the Merger, Enbridge and its subsidiaries own Union Gas through their ownership of Spectra Energy.

Enbridge is a public company whose common shares are listed on the Toronto and New York stock exchanges under the symbol ENB.

Our Board of Directors (the Board) is comprised of at least one-third independent directors with the remainder consisting of officers of Union Gas and Enbridge. There is no audit committee of the Board. The function of the audit committee is carried out by the Board during the review of Union Gas' Financial Statements.

New Appointments as a Result of the Merger

Effective February 27, 2017, Ms. Cynthia Hansen was appointed Director and Chair of the Board of the Company.

Effective April 13, 2017, PricewaterhouseCoopers LLP was appointed as new auditors of the Company replacing Deloitte LLP.

HIGHLIGHTS

	For the Years Ended December 31,		
($millions except where noted)	**2017**	2016	2015
Income			
Total operating revenues	**2,260**	1,849	1,972
Net income applicable to common shares	**232**	202	185
Dividends			
Dividends on preferred shares	**3**	3	3
Dividends on common shares	—	—	50
Assets and long-term liabilities[a]			
Total assets	**8,916**	8,227	7,190
Total long-term liabilities	**5,240**	4,830	4,321
Volumes of gas (10^6m^3)[b]			
Distribution volumes	**12,841**	13,376	13,881
Transportation volumes	**21,917**	20,759	20,824
Total throughput	**34,758**	34,135	34,705
Customers *(thousands)*	**1,475**	1,459	1,437
Heating degree days[c] *(degree Celsius)*			
Actual	**3,879**	3,789	4,104
Normal[d]	**4,066**	4,068	3,969
(Warmer) colder than normal	**(187)**	(279)	135

[a] 2015 amounts restated due to debt issue costs reclassification. See New Accounting Pronouncements section in our 2015 Annual Report for additional details.

[b] 10^6m^3 equals millions of cubic metres. One cubic metre is equivalent to 35.30096 cubic feet.

[c] A heating degree day is a measure of temperature that identifies the need for heating. A heating degree day occurs when the average daily temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius on a particular day equals 18 heating degree days.

[d] As per Ontario Energy Board approved methodology used in setting rates.

DIVIDENDS

	For the Years Ended December 31,		
	2017	2016	2015
Per Common Share	$—	$—	$0.86
Per Class A Preferred Share			
5.5% Series A	**$2.75**	$2.75	$2.75
6% Series B	**$3.00**	$3.00	$3.00
5% Series C	**$2.50**	$2.50	$2.50
Per Class B Preferred Share			
4.88% Series 10	**$0.58**	$0.54	$0.56

The declaration of dividends on the Common shares is at the discretion of the Board. In order to maintain the common equity component of the capital structure at the level approved by the Ontario Energy Board (OEB), we typically pay dividends to our parent company based on net income, less earnings reinvested in expansion capital projects. For 2017 we paid no dividends to GLBE due to our significant investment in expansion capital projects (2016 – $nil; 2015 – $50 million).

The indentures and agreements relating to our long-term debt obligations contain covenants limiting the payment of dividends. Certain debenture issues limit the payment of dividends such that dividends are not permitted, with certain exceptions, if immediately thereafter all indebtedness for money borrowed would exceed 75% of the total capitalization of Union Gas. We are in compliance with these provisions.

RESULTS OF OPERATIONS

	Three Months Ended December 31,			Twelve Months Ended December 31,		
($millions)	2017	2016	**Increase (Decrease)**	2017	2016	**Increase (Decrease)**
Gas sales and distribution revenue	551	470	**81**	1,873	1,529	**344**
Storage and transportation revenue	97	78	**19**	363	299	**64**
Gas commodity, storage and transportation costs	327	249	**78**	1,070	738	**332**
Operating margin[(a)]	321	299	**22**	1,166	1,090	**76**
Other revenue	11	9	**2**	24	21	**3**
Expenses[(b)]	197	204	**(7)**	768	724	**44**
Interest expense	44	42	**2**	171	161	**10**
Income tax expense	11	9	**2**	16	21	**(5)**
Net income	80	53	**27**	235	205	**30**
Net income applicable to common shares	79	52	**27**	232	202	**30**

(a) For more information on this non-GAAP measure see page 5.

(b) Expenses include Operating and maintenance, Depreciation and amortization, and Property taxes and other.

Three Months Ended December 31, 2017 compared to three months ended December 31, 2016

Operating margin. The $22 million increase was mainly driven by:

- a $13 million increase in residential customer usage of natural gas, primarily due to weather that was colder than in 2016, and
- a $12 million increase due to incremental transportation revenue primarily from the Dawn-Parkway expansion projects.

Expenses. The $7 million decrease was mainly driven by:

- a $13 million decrease in operating and maintenance expenses primarily due to lower demand side management (DSM) charges, that are recovered in delivery rates, partially offset by
- a $7 million increase in depreciation expense due to new projects placed into service.

Income taxes. The $2 million increase was mainly due to higher pre-tax income.

Twelve months ended December 31, 2017 compared to twelve months ended December 31, 2016

Operating margin. The $76 million increase was mainly driven by:

- a $40 million increase in transportation revenue primarily due to incremental revenue from the Dawn-Parkway projects,
- an $11 million increase in storage revenue primarily due to higher storage pricing and higher storage optimization,
- an $8 million increase in delivery rates,
- a $6 million increase in residential customer usage of natural gas, primarily due to weather that was colder than in 2016, and
- a $6 million increase from growth in the number of customers.

Expenses. The $44 million increase was mainly driven by:

- a $26 million increase in depreciation expense due to new projects placed into service, and
- a $14 million increase in operating and maintenance expenses primarily due to higher employee severance costs as a result of the Merger and higher employee related expenses.

Income taxes. The $5 million decrease was mainly due to lower effective tax rate primarily attributable to increased timing differences related to property, plant and equipment, partially offset by higher pre-tax income.

QUARTERLY RESULTS[a]

($millions)	Q1 2016	Q2 2016	Q3 2016	Q4 2016	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Gas sales and distribution revenue	565	295	199	470	726	349	247	551
Storage and transportation revenue	76	71	74	78	94	86	86	97
Other revenue	4	4	4	9	4	5	4	11
Total operating revenues	645	370	277	557	824	440	337	659
Net income (loss)	125	29	(2)	53	134	29	(8)	80
Net income (loss) applicable to common shares[b]	124	29	(3)	52	133	29	(9)	79

[a] Quarterly results have been extracted from financial statements prepared in accordance with U.S. GAAP.

[b] Earnings per share is not provided, since the Company is an indirect wholly owned subsidiary of Enbridge.

Seasonal Trends

The natural gas distribution business is highly seasonal due to volume-based rates and the significant effect of the winter heating season on volumes. This is typically reflected in strong first quarter results, second and third quarters that show either small profits or losses and strong fourth quarter results, subject to the impact of weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in Gas sales and distribution revenue are completely offset in Gas commodity, storage and transportation costs as a result of the associated regulatory recovery and refund mechanisms.

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.

REGULATORY MATTERS

Union Gas is regulated by the OEB pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides for different forms of regulation and competition in the energy (electricity and natural gas) industry in Ontario. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Application to Amalgamate

In November 2017, the Company and Enbridge Gas Distribution Inc. (EGD), 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, Union Gas and EGD 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 EGD. 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 Union Gas, EGD, and Enbridge's review and assessment of the regulatory outcomes and their respective Board of Directors approvals.

Rate Regulation

Our distribution rates, beginning January 1, 2014, are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,
- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between Union Gas and our customers, and
- an earnings sharing mechanism that permits Union Gas to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

On January 18, 2018, the OEB approved Union Gas' application for new rates effective January 1, 2018 pursuant to our incentive regulation framework. As a result of the OEB's findings in the decision, the impact on a typical residential customer will range from an increase of $9 to $14 annually depending on the customer's location within our service territory.

This rate application does not include the impacts of charges under the Province of Ontario's (the Province) Cap and Trade Program for the recovery of customer-related obligation costs and Union Gas' facility-related obligation costs effective January 1, 2018. Union Gas filed to recover these obligation costs associated with its 2018 Cap and Trade Compliance Plan with the OEB in November 2017. Union Gas is expecting a decision in the second half of 2018.

Commodity Rates

Union Gas and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis (QRAM), to ensure that customers' rates reflect future expected prices to the extent reasonably possible. The difference between the approved and the actual cost of gas incurred is deferred for future recovery from or repayment to customers. These differences are included in quarterly gas commodity rates and recovered from or refunded to customers over the subsequent 12 months. This allows us to adjust customers' rates closer to the time costs are incurred.

Annual Non-Gas Commodity Deferral Accounts Disposition

Non-gas commodity deferral accounts are filed for approval of disposition annually and typically collected or recovered over six months. In August 2017, the OEB approved collection of the 2016 non-gas commodity deferral account balances of $43 million beginning October 1, 2017.

Demand Side Management

We continue to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through our various DSM programs offered across all markets. As such, our 2018 rates include $63 million to recover forecast DSM spend. The 2018 budget was approved as part of the OEB Revised Decision in the 2015-2020 DSM Plan proceeding.

In December 2017, after receiving final audit results, we filed an application with the OEB for the disposition of the 2015 DSM deferral account balances. The impact is a net receivable from customers of approximately $8 million. Union Gas has requested a decision from the OEB in the first quarter of 2018 to allow recovery from customers to begin in the second quarter of 2018.

DSM deferral account balances for 2016 and 2017 will be filed for disposition after the 2015 DSM deferral decision has been received.

OEB Consultation on Pensions and Other Post-employment Benefits (OPEBs)

In May 2015, the OEB invited interested rate-regulated utilities, in both the gas and electricity sectors, to participate in a consultation on pensions and OPEBs. The objectives of the consultation are to develop standard principles to guide the OEB's review of pension and OPEB costs in the future, to establish specific information requirements for applications and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated utilities. In September 2017, the OEB released its final "Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs" report, which established the accrual accounting method as the default method on which to set rates for pension and OPEBs in cost-based applications. The report also provides for the establishment of a variance account to track the difference between the forecast accrual amounts in our rates and actual cash contributions effective January 1, 2018. The financial impacts of the OEB's final report are not expected to be material.

OEB Consultation on Cap and Trade

In September 2016, the OEB released its final "Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities" report. The framework is used to guide the OEB's assessment of natural gas distributors' Cap and Trade Compliance Plans, including the cost consequences of these plans, monitoring and reporting, customer outreach, confidentiality of the Cap and Trade information and the mechanism for the recovery of costs in rates. The OEB determined that charges related to the recovery of customer-related obligation costs, Union Gas' facility-related obligation costs and administrative costs relating to the implementation and ongoing operation of the Cap and Trade Program will be included in the delivery charge on customer bills. In November 2016, we filed our 2017 Compliance Plan and the OEB issued an interim rate order approving the associated Cap and Trade costs for recovery from customers effective January 1, 2017. In September 2017, the OEB issued its Decision and Order on Union Gas' 2017 Compliance Plan. The OEB noted that the plan was based on reasonable option analysis, optimized decision-making and risk management process and analysis. Union Gas received final rate approval from the OEB in November 2017. For more information, see Climate Change within Risk Factors.

Cap and Trade Deferral Accounts

In September 2017, the OEB approved the establishment of the Greenhouse Gas Emissions Compliance Obligation – Customer Related Deferral Account and the Greenhouse Gas Emissions Compliance Obligation – Facility Related Deferral Account, as part of the approval of Union Gas' 2017 Compliance Plan. These deferral accounts will separately track the variance between the actual costs incurred related to the customer-related greenhouse gas (GHG) obligation cost and the facility-related GHG obligation cost and the amount collected through rates.

Dawn to Parkway Projects

Union Gas has just completed the 2017 Dawn to Parkway Expansion project which was the final phase of a three year growth project which increased the firm capacity of that system by 20 percent. In the third quarter of 2017, new compressors and associated facilities at the Lobo and Bright Compressor Stations went into service as part of the Dawn to Parkway 2017 Expansion Project. The installation of a Dawn compressor was completed and placed into service in October 2017. For further details regarding these projects, see Liquidity and Capital Resources.

Panhandle Reinforcement Pipeline Project

In February 2017, the OEB approved the construction and rate recovery of the Panhandle Reinforcement Pipeline from the Dawn Compressor Station to the Dover Transmission Station to serve firm demand growth in southwestern Ontario. The pipeline was placed into service in November 2017. For further details regarding this project, see Liquidity and Capital Resources.

Community Expansion

In November 2016, the OEB released its Decision with Reasons (Decision) for a generic community expansion proceeding. The decision granted the ability for the distributor to charge stand alone rates or surcharges for each new community to ensure that the projects are self-funding over the life of the project. Union Gas filed its updated community expansion application and evidence proposals for four projects at the end of March 2017.

In the third and fourth quarter of 2017, the OEB approved the rate surcharge proposal for four communities and granted leave to construct for the three communities that required approval. The Lambton Shores and Kettle Point First Nation and Milverton projects had 2017 in-service dates, and projects to service Prince Township and Moraviantown First Nation are expected to enter service in 2018. The Moraviantown First Nation project will only proceed if an Ontario Government (the Government) grant is awarded.

In October 2016, Union Gas filed its Common Infrastructure Plan (CIP) Proposal to serve the area covered by the South Bruce Expansion application. An OEB administered process to determine the successful competing project proponent is currently underway, with an OEB decision expected in the first half of 2018.

On July 30, 2017, Union Gas submitted grant applications to the Government for 45 community expansion and five economic development projects, for a total grant amount of $330 million. The Government has set aside approximately $70 million for community expansion grants and $30 million for economic development grants. Union Gas expects the Government to publicly announce the successful grant applicants in the first quarter of 2018, which will allow construction for a limited number of additional projects in 2018 through 2020.

For further details regarding these projects, see Liquidity and Capital Resources.

Sudbury Replacement Project

In September 2017, the OEB granted leave to construct for a new pipeline in the City of Greater Sudbury. The new pipeline will replace the existing pipeline, addressing integrity issues and future growth requirements. The total capital cost of the pipeline is expected to be approximately $74 million with service to customers expected in November 2018. For further details regarding this project, see Liquidity and Capital Resources.

Kingsville Transmission Reinforcement Project

In January 2018, we applied to the OEB for leave to construct and cost recovery approval for a new pipeline, extending from an interconnect at the existing Nominal Pipe Size (NPS) 20 Panhandle Line in the Town of Lakeshore to a new station in the Town of Kingsville. The total capital cost of the pipeline is expected to be approximately $106 million with service to customers expected in November 2019. For further details regarding this project, see Liquidity and Capital Resources.

GAS SUPPLY

Union Gas ensures that customers receive a secure and diverse gas supply portfolio that is cost-effective. We continuously monitor and evaluate the new and changing natural gas supply dynamics to determine what opportunities exist for our customers.

Union Gas currently holds a diverse portfolio of transportation contracts that allow for the purchase of natural gas from various supply basins and suppliers across North America. The price that Union Gas pays for natural gas is a market sensitive price, typically based on the NYMEX Physical Basis or an index depending on where Union Gas sources natural gas from across North America. This includes, but is not limited to, indices such as Alberta, Michigan and Chicago.

The North American natural gas market has experienced and is expected to continue to experience change. While production from some conventional North American natural gas basins is in decline, production from shale gas formations continues to exceed expectations, and the supply economics generally favour shale gas formations which are closer to the consuming markets.

In support of this change in natural gas flows, in December 2015, the OEB approved our application for the pre-approval of the cost consequences of entering into a long-term transportation capacity contract with the Nexus Gas Transmission pipeline (NEXUS), which is expected to be in service in the third quarter of 2018. NEXUS will transport natural gas from the Appalachian region of the U.S. Northeast, which is the single largest and fastest growing producing region of natural gas in North America, into Dawn. The NEXUS project is being jointly developed by DTE Energy Company and Enbridge.

The overall increase in natural gas supply in North America resulting from shale gas development has led to current and projected, low and stable natural gas prices.

Renewable Natural Gas

In Ontario, there is an increasing desire to reduce the carbon intensity of natural gas which Union Gas delivers to customers and uses in its own operations. The Government of Ontario and the OEB have clearly and consistently articulated support for the pursuit of renewable natural gas (RNG) as a component of utility gas supply portfolios. RNG is biogas that has been upgraded to pipeline quality natural gas by removing impurities. By upgrading the quality, it becomes possible to inject the biogas into the natural gas distribution system in Ontario and to distribute a renewable alternative gas to customers via the existing natural gas pipeline grid. Union Gas is exploring options to source RNG as part of its gas supply purchase portfolio while minimizing cost impacts to customers. Union

Gas has made a proposal to the OEB for approval of an RNG purchase mechanism as part of its 2018 Cap and Trade Compliance Plan filing. The cost of RNG is typically higher than the combined cost of carbon and the cost of conventional natural gas today and is expected to be for the foreseeable future. Union Gas' proposal to the OEB contemplates government funding to offset the higher cost of RNG. Natural gas customers contribute to Cap and Trade program funds through the cost of carbon included in natural gas rates. Access to the Cap and Trade funds, distributed by the government, to support RNG ensures that ratepayers are not paying a premium for RNG in addition to already contributing to Cap and Trade in natural gas rates. Government funding provides access to Cap and Trade proceeds specifically allocated for RNG, supporting the economic and environmental benefits that RNG can provide in optimizing the use of existing natural gas assets while reducing the Province's carbon footprint. If approved, Union Gas will pursue the purchase of RNG, through a request for proposal process, as early as 2018.

OUTLOOK

Gas Sales and Distribution

We expect that the long-term demand for natural gas in Ontario will remain relatively stable with continued growth in peak day demands, subject to the impacts of governmental actions to reduce GHG emissions. Some modest growth driven by low natural gas prices is expected to continue given the significant price advantage relative to their alternate energy options, with specific interest coming from communities that are not currently serviced by natural gas.

We continue to focus on promoting conservation and energy efficiency by undertaking activities focused on reducing natural gas consumption through our various DSM programs offered across all markets. For 2017, the OEB approved DSM budget was $59 million and will increase to $63 million in 2018 and $64 million by 2020.

We are also pursuing other opportunities to assist in lowering GHG emissions. Union Gas and EGD have partnered with the Government of Ontario to deliver a home renovation program using $100 million in funding over three years through the Green Investment Fund program. Union Gas will continue to pursue options to promote RNG as well as compressed natural gas as alternative fuel sources.

Storage and Transportation

The storage and transportation marketplace continues to respond to changing natural gas supply dynamics including a robust supply environment. In recent years, the robust North American gas supply balance, due mainly to the development of shale gas volumes including the Alberta, British Columbia, Marcellus and Utica shale areas, has resulted in lower commodity prices and narrower seasonal price spreads. Unregulated storage values are primarily determined based on the difference in value between winter and summer natural gas prices. Storage values have been relatively stable to slightly rising over 2016 and 2017 as the North American natural gas supply and demand slowly returned to a more balanced position.

We expect that demand for natural gas in North America will continue to see low annual growth over the long-term with continued growth in peak day demands. The development of the Marcellus and Utica Shale areas is leading to significant new pipeline infrastructure to connect these supplies to the North American pipeline grid and the associated natural gas consuming market areas. The proximity of our storage and transportation facilities and our interconnections with major U.S. markets in the Great Lakes region and in the northeast U.S. support long-term growth opportunities. These opportunities focus on connecting new supply sources to Dawn and ensuring that there is sufficient transportation capacity on Union Gas' transmission system and pipelines downstream of Parkway to serve eastern Canadian and U.S. markets. Connectivity to Ontario continues to increase with new pipelines under construction for service beginning in 2018. Further, gas supply access at the Dawn Market hub is increasing due to the TransCanada Pipelines Limited's Long Term Fixed Price service from Empress.

In response to customer demand to access new and growing supply at Dawn, Union Gas has just completed the 2017 Dawn to Parkway Expansion project which was the final phase of a three year growth period which increased the firm capacity of that system by 20 percent. For additional information regarding this and other projects, see the Regulatory Matters section.

RISK FACTORS

Our earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, our business and earnings level may be adversely affected by a number of risks, including but not limited to the risks described below.

Climate Change

Ontario's Cap and Trade Program came into effect on January 1, 2017 with the purpose of reducing GHG emissions in the Province. It covers natural gas distributors (and others) and puts a price on certain GHG emissions. Union Gas is required to purchase emission allowances or credits on behalf of most of its customers and for its own emissions.

On September 22, 2017, the Ontario government signed an agreement linking the carbon markets of Quebec, Ontario and California, effective January 1, 2018. This linkage which has been enabled in Ontario with various GHG 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 keep compliance costs for our customers down. 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. Impacts on carbon pricing that may result from policy change may affect the price of natural gas and, in turn, potentially affect the demand for natural gas.

In June 2016, the Province also issued its Climate Change Action Plan (the CCAP), a high-level policy that describes how proceeds from the Cap and Trade program may be used over the next five years to reduce GHG emissions in Ontario. Longer term impacts of the Cap and Trade program and the CCAP and associated programs and their future effects on Union Gas' results of operations, financial position or cash flows remain uncertain.

Union Gas received approval from the OEB to incorporate forecasted Cap and Trade costs in rates effective January 1, 2017. Variances from the forecast will be captured in a deferral account for future disposition. Union Gas will continue to incorporate any impacts on its revenues, operating costs or capital expenditures of the Cap and Trade program and the CCAP into applicable regulatory applications, including by seeking cost recovery through rates, and will continue to actively monitor and respond to actions and initiatives resulting from the CCAP.

The Company submitted and received supportive endorsement from the OEB of its 2017 Compliance Plan, and has filed, and is seeking approval of its 2018 Compliance Plan. The Compliance Plans detail how Union Gas 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 GHG emissions to the Ontario Ministry of Environmental and Climate Change (MOECC), Environment and Climate Change Canada (ECCC), 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. Union Gas continues to monitor regulation developments and attend stakeholder consultations in Ontario.

Union Gas utilizes an emissions data management process 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.

In late 2016, the Government of Canada announced the Pan-Canadian Framework on Clean Growth and Climate Change (Framework). The Framework is intended to support Canada's international commitments to reducing GHG emissions and addressing climate change. The Framework includes elements such as national carbon pricing benchmarks (which are intended to create a uniform carbon price across Canada), complementary actions and innovation. In May 2017 and January 2018, the Government of Canada issued its proposed details to implement a backstop carbon price in provinces and territories that do not meet the national benchmark carbon price (as described in the Framework) by the end of 2018. The incremental impact of the Framework on Ontario's Cap and Trade system and CCAP is unknown at this time, but continues to be closely monitored.

In May 2017, ECCC published the "Proposed Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)" (the Proposed Methane Regulations), to help reduce methane emissions from Canada's oil and gas sector. The Proposed Methane Regulations are expected to impose new regulatory requirements to reduce methane emissions at natural gas transmission and storage facilities. Union Gas will continue to monitor developments in the regulation, assess potential impacts and participate in ongoing consultations with ECCC. The Proposed Methane Regulations are expected to be finalized in 2018 and to take effect between 2020 and 2023 depending on the specific emission type.

Market Risk

Sales to industrial customers are affected by general economic conditions, the absolute and relative price of energy, foreign exchange rates, local and global competition and government legislation and regulations. The modest growth seen in 2017 in the North American economy is expected to further improve in 2018. Ontario's natural gas energy market will benefit from this improvement while also being impacted by negative market forces arising from globalization and more energy efficient technology.

Electricity demand in Ontario is showing little growth due to permanent industrial demand destruction and energy conservation that has occurred, resulting in an oversupply of electricity. That, coupled with the extension of previously declared end of life nuclear units at Pickering, has resulted in the non-renewal of several power purchase agreements with some non-utility natural gas fueled power generators (specifically, Northland Cochrane, Atlantic North Bay and Kapuskasing). Other factors affecting the power market include the province of Quebec's announcement to sell hydro-electric power to Ontario displacing gas-fired power generation, and the Independent Electricity System Operator's (IESO's) announced intent to replace expiring long term power purchase agreements with capacity auctions. As the IESO continues to advance its market renewal initiative, the commercial framework for gas-fired power generators could continue to change. These policy and market dynamics could impact our ability to re-contract with existing power generators moving forward. Revenues from gas-fired power generators have declined due to non-renewals of power purchase agreements with Natural Gas generators noted above.

Sales to Union Gas' residential, small commercial and small industrial customers are affected by the number of new customer additions to the system, the price of natural gas, the warming trend in weather that is not fully reflected in rates, and the continued shift to higher efficiency. New customer additions in 2018 are expected to remain consistent with 2017 trends. High electricity prices are furthering the conversion market.

A large quantity of our transportation capacity is subject to renewal on an annual basis. Our standard contract terms provide automatic renewal of contracts, after the initial term, for one year at a time unless the customer provides two years' prior notice of termination. Future termination notices and reselling terminated capacity are dependent on the demand for the capacity which is affected by the changing flows of gas in the Great Lakes region. It is also dependent on the availability of transportation downstream of Parkway. Any new projects that create downstream capacity will provide access to Dawn supplies for customers located in the downstream Ontario, Quebec and northeast U.S. markets. We have received notice of termination for Dawn-Parkway capacity of approximately 0.19 Bcf/d in 2018 and 0.05 Bcf/d in 2019. This terminated capacity will be available to serve new transportation demand as well as growth in in-franchise loads.

Commodity Price Risk

Fluctuations in natural gas prices affect our gas purchase costs for our own operating requirements as well as for the gas supply costs we incur for and collect from our system customers. Our gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

Carbon Price Risk

Union Gas is required to purchase emission allowances or credits on behalf of most of our customers and for our own emissions. Fluctuations in carbon prices affect our Cap and Trade compliance costs for our own operations as well as the compliance costs we incur for and collect from our customers. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

Credit Risk

Credit risk represents the loss that we could incur if a counterparty fails to perform under its contractual obligations. We analyze the customer's financial condition prior to entering into an agreement, obtain collateral when appropriate, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

Our credit exposure consists of both the risk of collecting receivables for services provided, as well as the risk related to gas imbalances that occur as a regular part of the services provided in both the direct purchase market and ex-franchise market.

In the normal course of operations, we provide gas loans to other parties from our holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2017 was $93 million (2016 – $84 million). We manage our credit exposure related to gas loans by subjecting these parties to the same credit policies used for all customers.

Weather Risk

As the primary component of our rates is volume based, our revenue levels approved by the OEB are impacted by weather. The volume forecasts used to determine the rates approved by the OEB assume normal weather conditions. Normal weather, as mandated by the OEB, is based on a 50:50 weighting of the 30-year average forecast and 20-year trend forecast respectively, for 2013 forward. Since a large portion of the gas distributed to the residential and commercial markets is used for space heating and is charged using volume-based rates, differences from normal weather have a significant effect on the consumption of gas and on our financial results.

Regulatory Risk

Our natural gas assets and operations are subject to regulation by federal, provincial and local authorities including the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including the ability to determine terms and rates for services, acquisitions, construction, expansion and operation of facilities, issuance of equity or debt securities and dividend payments.

In addition, regulators in Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Our pipelines and related facilities are also regulated by the Ontario Technical Standards and Safety Authority (TSSA) while a few are regulated by the National Energy Board of Canada (NEB). Through our participation on the TSSA Natural Gas Advisory Council and associated Risk Reduction Groups we have the opportunity to provide input on the direction of regulatory changes. Union Gas also has extensive engagement on the Canadian Standards

Association Technical Code and Standards Committees. Amendments to the Ontario regulations made by the TSSA could have an impact on our Integrity Management Program and the direction the U.S. industry is taking may prompt some further regulatory requirements. Given the mature status of our integrity management programs, potential changes are not expected to have a material impact on the organization. We have very limited NEB regulated assets, so the amendments to the NEB Management Systems and Performance Measures are not expected to have a significant impact on our business. Union Gas utilizes a comprehensive and integrated Operations Management System (OMS) to manage the operations of the organization. We have aligned our OMS with the new Enbridge Integrated Management System framework, ensuring compliance with both legal and regulatory requirements and the Enbridge corporate standard. We have taken the NEB requirements into account and have enhanced our OMS to be able to meet the requirements. The OMS provides the necessary structure and discipline to ensure we operate in a way that provides for demonstrated legal and regulatory safety and compliance.

Competition Risk

As our distribution business is regulated by the OEB, it is generally not subject to third-party competition within our distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of Union Gas' system may be permitted, even within our franchise area. In addition, the OEB decision in the Generic Proceeding on Community Expansion provides a framework that facilitates the entry of new participants and allows for competition as it pertains to serving rural and First Nations communities that do not currently have access to natural gas.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Storage Market Risk

We sell our storage services based on seasonal natural gas market price spreads and volatility. If seasonal natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage capacity through a portfolio of varying contract terms may not protect us from significant variations in storage revenues, including possible declines as contracts renew.

Our standard storage contract terms do not allow for automatic renewals but typically have contract terms of one to five years. Storage prices are subject to market conditions at the time the contracts are renegotiated. Given the changes occurring to the Province's power generation markets, there is risk associated with the renegotiation of expiring storage contracts with the Province's power generators, including volume and price risk.

Gas Measurement Risk

In determining the quantities of gas delivered and received, differences arise from the measurement process. The cost of these differences is referred to as unaccounted for gas (UFG). Rates for storage, transmission and distribution of gas, approved by the OEB effective January 2013, were reset to recover an estimate of UFG based on actual experience in the previous three years, which was lower than amounts previously included in rates. Variances between the estimate included in rates and the actual cost of UFG result from measurement and estimation errors. Under the current incentive regulation framework, the impact on our financial results arising from these variances is limited to $5 million.

Financing Risk

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from operations and to fund investments originally financed through debt. Our long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We are subject to long-term debt covenants that include a limitation on the payment of dividends and requirements to satisfy specific interest coverage ratios prior to the issuance of additional long-term debt. Although we do not anticipate any impact to our current financing plans, reduced earnings may limit the payment of future dividends and the level of new long-term debt available to us. We maintain a revolving credit facility to backstop our commercial paper programs for short-term borrowings. This facility includes a financial covenant which limits the amount of debt that can be outstanding as a percentage of total capital. Failure to maintain this covenant could preclude us from issuing commercial paper or borrowing under the revolving credit facility and could require immediate pay down of any outstanding drawn amounts under other revolving credit agreements, which could adversely affect our cash flow.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings could make our costs of borrowing higher or access to funding sources more limited.

Human Resources Risk

Union Gas' workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect our ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent issues that are being addressed by Union Gas. All of Union Gas' collective agreements expire between December 2017 and May 2018. The labour relations group is in the process of meeting with the various unions to negotiate new agreements.

Performance Risk

We have extensive contractual relationships with natural gas producers, customers, marketers, commercial enterprises, industrial companies and others. The risk of non-performance by us or a contracting party may be analyzed and mitigated but it cannot be entirely eliminated and could affect our earnings, financial position and cash flows. Ongoing consolidation of customers and partners may increase the severity of a default.

Litigation Risk

Union Gas, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, we have no reason to believe that the ultimate outcome of such matters currently known to us could have a material effect on our Financial Statements.

Facility Risk

We carry on business through a large and complex array of natural gas transmission, storage and distribution assets. These facilities, like any other industrial operations, are subject to outages from time to time. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

Political Risk

The Province is operating with a large financial deficit and significant spending commitments. As such, it is expected that the current provincial Government may look for new sources of revenues, including non-tax revenue streams such as fees and levies. At this time, we do not anticipate any material financial impact to Union Gas.

Environmental, Health and Safety Risk

There are a variety of hazards and operating risks inherent in natural gas storage transmission and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centres, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by these risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

Protecting Against Potential Terrorist Activities

The potential for terrorism because of the high profile of the natural gas industry has subjected our operations to increased risks that could have a material adverse effect on our business. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism, including cyber-terrorism, has subjected our operations to increased risks that could have a material effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business. A cyber attack could also lead to a significant interruption in our operations or unauthorized release of confidential information or otherwise protected information, which could damage our reputation or lead to financial losses.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Pension Risk

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Land Rights

Various aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas' facilities, and the gas supply areas served by those facilities, are located. In addition to aboriginal groups, other landowners have also claimed their rights in Union Gas' franchise area. The existence of these claims could give rise to future uncertainty regarding land tenure and expansion depending upon their negotiated outcome. We continue to proactively plan and manage the risks associated with these issues and work with provincial government regulators in that regard.

Capital Project Execution Risk

A portion of our growth is accomplished through the construction of new pipelines and storage facilities as well as the expansion of existing facilities.

Construction of these facilities is subject to various regulatory, development, operational and market risks, including: the ability to obtain necessary approvals and permits from regulatory agencies and municipalities on a timely basis and on acceptable terms, and to maintain those approvals and permits issued and satisfy the terms and conditions imposed therein; the availability of skilled labour, equipment, and materials to complete expansion projects; potential changes in federal, provincial and local statutes and regulations, including environmental requirements, that may prevent a project from proceeding or increase the anticipated cost of the project; impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms; the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation, foreign exchange or increased costs of equipment, materials or labour, weather, geologic conditions, or other factors beyond our control, that may be material; and general economic factors that affect the demand for natural gas infrastructure.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve their expected investment return, which could affect our earnings, financial position and cash flows.

Shale Gas Development

Recent community and political pressures have arisen around the production and transmission of natural gas originating from shale basins. Although we continue to believe that natural gas will remain a viable energy solution for Canada and the U.S., these pressures could increase costs and/or cause a slowdown in pipeline project development and/or the production of natural gas from these shale basins. This could negatively affect our growth plans and our access to this natural gas supply.

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

During the third quarter of 2017, Union Gas took assignment of a number of EGD customer storage contracts, some of which were denominated in USD. EGD also novated, to Union Gas, cash flow hedges that were used to manage exposure to changes in currency exchange rates in the assigned storage contracts.

RELATED PARTY TRANSACTIONS

We occasionally perform services for and incur costs on behalf of Enbridge, Spectra Energy and its affiliates (related parties), which are subsequently reimbursed. Likewise, certain related parties may perform services for or incur costs on behalf of us, which are then reimbursed by us. We also provide and purchase gas, storage and transportation services to related parties. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, related parties perform centralized corporate functions for us, pursuant to agreements with related parties, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. We reimburse related parties for the expenses to provide these services as well as other expenses they incur on our behalf. Related parties charge such expenses based on the cost of actual services provided or using various allocation methodologies based on our percentage of assets, employees, earnings or other measures, as compared to Enbridge and Spectra Energy's other related parties.

In the normal course of operations, we provide or obtain funds from Westcoast on an unsecured basis. We also have a promissory note to borrow up to $150 million from GLBE on an unsecured basis.

On July 31, 2017, we entered into a Gas Storage Service Agreement (GSSA) with EGD, a new affiliated company under common control as a result of the Merger, whereby we contracted all of EGD's unregulated storage space and deliverability effective September 2017. In conjunction with the GSSA, we entered into a Storage Contracts Assignment Agreement with EGD whereby we took assignment of EGD's customer contracts related to the assigned unregulated storage space, effective September 2017. On September 29, 2017, EGD novated all of its derivative instruments relating to foreign exchange forward contracts to the Company.

Our transactions with related parties are as follows:

($millions)	**Storage and transportation revenue**	**Gas commodity, storage and transportation expense**	**Shared service charges (receipts)[(a)]**	**Total**
2017				
St Clair Pipelines Partnership, a division of Westcoast	—	1	—	1
Pipeline and Field Services, a division of Westcoast	—	—	(4)	(4)
Westcoast Energy Inc.	—	—	(1)	(1)
Spectra Energy Gas Transmission LLC	—	—	12	12
Sarnia Airport Storage Pool Limited Partnership	(1)	5	—	4
Market Hub Partners L.P.	—	1	—	1
Enbridge Gas Distribution Inc.	(113)	7	—	(106)
Tidal Energy Marketing Inc.	(4)	—	—	(4)
Tidal Energy Marketing (US) LLC	—	5	—	5
St. Lawrence Gas Company Inc.	(1)	—	—	(1)
Express-Platte Pipeline L.P.	—	—	(1)	(1)
Total	(119)	19	6	(94)
2016				
St Clair Pipelines 1996, a division of Westcoast	—	—	(2)	(2)
Pipeline and Field Services, a division of Westcoast	—	—	(4)	(4)
Spectra Energy Empress L.P.	—	21	—	21
Spectra Energy Gas Transmission LLC	—	—	21	21
Sarnia Airport Storage Pool Limited Partnership	—	4	—	4
Total	—	25	15	40

[(a)]Excludes compensation arrangements.

Net amounts due from (to) related parties are as follows:

($millions), net	**2017**	2016
Enbridge Gas Distribution Inc.	**11**	—
Tidal Energy Marketing Inc.	**1**	—
Spectra Energy Gas Transmission LLC	**(4)**	(1)
Enbridge Inc.	**(2)**	—
Westcoast Energy Inc.	—	(253)
Other	**1**	—
Total[(a)]	7	(254)

[(a)]At December 31, 2017, $9 million (2016 – $5 million) is recognized in Accounts payable and accrued charges, $16 million (2016 – $4 million) is recognized in Accounts receivable and other, and $nil (2016 – $253 million) is recognized in Short-term borrowings on the Balance Sheets.

LIQUIDITY AND CAPITAL RESOURCES

We invest surplus cash in short-term investment grade money market instruments with highly creditworthy counterparties.

We will rely upon cash flows from operations and various financing transactions, which may include issuances of short-term and long-term debt, capital contributions and utilization of loans from Westcoast and GLBE, to fund our liquidity and capital requirements. We have access to a revolving credit facility that is used principally as a back-stop for our commercial paper program, which supports our short-term working capital fluctuations and temporary funding of capital expenditures.

Changes in Cash Flow	For the Years Ended December 31,	
($millions)	**2017**	2016
Operating activities	**724**	439
Investing activities	**(1,030)**	(1,036)
Financing activities	**298**	619

Operating Activities

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn throughout the heating season. December year-end inventory levels decrease and thus contribute to a positive cash flow from operations during the first quarter. After the heating season ends, inventory is replenished for the next heating season. During the third quarter, gas inventory injections typically exceed withdrawals, negatively affecting cash flows. During the fourth quarter inventory decreases as withdrawals exceed injections.

Some of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically use more gas than is delivered to us and we collect cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a negative cash flow. These are normal seasonal trends.

Cash provided by operating activities increased primarily due to changes in working capital, specifically related to the GHG compliance obligations created by the Company's customers.

Investing Activities

Investing activities include capital expenditures for Property, plant and equipment and Intangible assets. The tables below are a summary of capital expenditures:

	For The Years Ended December 31,		
	2018	2017	2016
	(estimated)		
Storage and transmission	23%	61%	73%
Distribution	67%	33%	24%
General equipment	10%	6%	3%
Total capital expenditures	100%	100%	100%

	For The Years Ended December 31,		
($millions)	2018	2017	2016
	(estimated)		
Expansion projects	336	528	834
Maintenance projects	247	225	202
Total capital expenditures	583	753	1,036

Capital expenditures for 2017 were lower compared to 2016 primarily due to the Dawn to Parkway Expansion and Burlington-Oakville projects that were placed into service in 2016.

In 2017, the following key expansion projects were placed into service:

- 2017 Dawn to Parkway – A 0.4 Bcf/d expansion of the Dawn to Parkway transmission system consisting of the addition of a new 44,500 horsepower compressor at each of our Dawn, Lobo and Bright Compressor Stations, which were placed into service in the third and fourth quarters of 2017.
- Panhandle Reinforcement – 0.1 Bcf/d of transmission capacity along Union Gas' Panhandle System, meeting future residential, commercial and industrial demands along the Chatham and Windsor corridor. The project consisted of replacing 40 km of 16 inch pipe with 36 inch pipe and station modifications at Dawn and other Panhandle stations. The project went into service in November 2017.
- Community Expansion – Union Gas brought natural gas to two new communities in 2017, Lambton Shores and Kettle Point First Nation and Milverton. Approximately 60 kms of pipeline was installed which will enable us to attach over 1,000 customers.

The 2018 expansion capital expenditures reflect our continued assessment of the timing of projected long-term market requirements and general economic conditions. Significant 2018 expansion project expenditures are expected to include:

- Community Expansion – Plans are in place to provide natural gas to continue community expansion, with an additional three communities in 2018. All of these projects will enable long term organic growth.
- Sudbury Lateral – The 2018 Sudbury Lateral project entails the replacement of two separate sections of the pipeline originally installed in 1958. The construction involves replacing 19.8 km of the NPS 10 and NPS 12 pipeline with NPS 12 pipeline between Coniston Primary Station and Walden Town Border Station. The project will improve reliability on the Sudbury System and by increasing the diameter of the replacement line, allow for future growth.
- Kingsville Transmission Reinforcement – This pipeline project will provide 0.06 Bcf/d of capacity to serve firm demand growth along Union Gas' Panhandle System in southwestern Ontario. The project consists of the construction of a new 19 km NPS 20 pipeline originating at Union Gas' existing Panhandle Transmission pipeline and a new transmission station in the Kingsville area. The expected capital cost of this project is approximately $106 million and will be filed with the OEB in the first quarter of 2018. Subject to OEB approval of the facilities and related recovery under the Incremental Capital Module (ICM) included in the MAADs application, construction will begin in the spring of 2019 with an expected in-service date of November 1, 2019.

Consistent with 2017, the 2018 maintenance expenditures are for maintaining the integrity of existing pipelines and related infrastructure.

Investing activities in 2017 also included cash flows related to GHG compliance instruments obtained by the Company that will be used to relieve customers' GHG obligations following the completion of the initial compliance period of January 1, 2017 through December 31, 2020.

As outlined in the financing activities discussion that follows, we have sufficient financing available to meet our investing requirements. Management expects that financing of 2018 projects will be done through a combination of cash generated from operations, available debt facilities, capital contributions and issuance of long-term debt.

Financing Activities

The primary factors decreasing cash flow from financing activities for 2017 compared to 2016 was the repayment of short-term borrowings, partially offset by lower repayment of debt in 2017 compared to 2016, a $30 million capital contribution received from GLBE in 2017 and an increase in commercial paper.

The declaration of dividends on the Common shares is at the discretion of the Board. In order to maintain the common equity component of the capital structure at the level approved by the OEB, we typically pay dividends to our parent company based on net income, less earnings reinvested in expansion capital projects. For 2017, no dividends were paid to GLBE, due to our significant investment in expansion capital projects (2016 – $nil).

Available Credit Facility and Restrictive Debt Covenants

			Commercial Paper Debt Outstanding at	
($millions)	**Expiration Date**	**Credit Facility Capacity**	**December 31, 2017**	December 31, 2016
Multi-year syndicated[a]	2021	700	**485**	333

[a] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 67.6% at December 31, 2017 (December 31, 2016 – 69.0%). Commercial paper issuances, net of discount, are back-stopped by the credit facility.

This facility is intended to be used primarily to manage the significant changes in working capital experienced by Union Gas as a result of volumes and prices associated with natural gas purchases and sales. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime rate. Our 2017 commercial paper peaked in October at $700 million (2016 – peaked in December at $333 million).

The available credit facility carried a weighted average standby fee of 0.085% on the unused portion.

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2017 and December 31, 2016 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of our short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2017 was 1.28% (2016 – 0.87%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2017 was fourteen days (2016 – 8 days).

Our credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2017 and December 31, 2016, we were in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

Total interest paid on short term debt in 2017 was $6 million (2016 – $1 million).

Union Gas and certain affiliates have, in aggregate, access to a $400 million demand letter of credit facility. As of December 31, 2017, Union Gas had no outstanding letters of credit under this facility.

Other Financing Matters

We maintain a current base shelf prospectus with the Canadian securities regulators, which enables ready access to Canadian public debt capital markets. On March 28, 2017, we filed a new $1.5 billion base shelf prospectus which provides for the issuance of medium-term note debentures. The new shelf prospectus replaces the previous one that expired on January 4, 2017. As of December 31, 2017, we had $1 billion available for the issuance of medium-term note debentures under the base shelf prospectus, which expires on April 28, 2019.

In November 2017, we issued $250 million of unsecured 2.88% medium-term note debentures, due November 2027 and $250 million of unsecured 3.59% medium-term note debentures, due November 2047. Net proceeds from the offerings were used for repayment of short-term debt and debt maturities, capital expenditures and general corporate purposes.

OUTSTANDING SHARES[a]

	December 31, 2017	December 31, 2016
Preferred Shares		
5.5% Cumulative Redeemable Class A Preferred Shares, Series A	**47,672**	47,672
6% Cumulative Redeemable Class A Preferred Shares, Series B	**90,000**	90,000
5% Cumulative Redeemable Class A Preferred Shares, Series C	**49,500**	49,500
4.88% Cumulative Redeemable Convertible Class B Preferred Shares, Series 10	**4,000,000**	4,000,000
Common shares	**57,822,650**	57,822,650

[a] Outstanding share information is provided as of February 16, 2018.

CONTINGENCIES AND COMMITMENTS

Environmental, Health and Safety

In April 2016, the MOECC issued a Director's Order (Order) naming Union Gas, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of Union Gas in Hamilton. In May 2016, Union Gas appealed the Order, and in June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MOECC's Director, stayed the application of parts of the Order. The Tribunal has extended the stay of the Order several times, which has allowed the owner of the property (with the cooperation of the adjacent owners) to prepare a plan of action, including discussions with the MOECC and other neighbours (City of Hamilton and Infrastructure Ontario). Union Gas continues to monitor the matter, and to cooperate with the owner of the source property, the MOECC and other adjacent owners. The risk of material environmental liability is unknown at this time.

Contractual Obligations

The table below is a summary of our contractual payment obligations, due by period.

($millions)	Total	2018	2019-2020	2021-2022	Thereafter
Long-term debt [a]	6,503	570	294	607	5,032
Operating leases	33	7	13	13	—
Purchase obligations[b]	2,407	509	473	311	1,114
Retirement plan contributions[c]	20	20	—	—	—
Total contractual obligations[d]	8,963	1,106	780	931	6,146

[a] Includes estimated scheduled interest payments over the life of the associated debt.

[b] Includes: firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; and contractual obligations for engineering, procurement and construction costs for pipeline projects. Due to a timing uncertainty, all procurement obligations have been included in 2018 as we are unable to reasonably estimate the payments due by period.

[c] We are unable to reasonably estimate retirement plan contributions beyond 2018 due primarily to uncertainties about market performance of plan assets.

[d] Excludes cash obligations for asset retirement activities. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Union Gas may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation, annual insurance premiums that are necessary to operate the business and regulatory liabilities because Union Gas is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude deferred income taxes and investment tax credits on the Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year. Our analysis also indicated that there are no expected payments and interest related to uncertain tax positions for 2018. We are unable to reasonably estimate the timing of uncertain tax positions and interest payments in years beyond 2018 due to uncertainties in the timing of cash settlements with taxing authorities.

NEW ACCOUNTING PRONOUNCEMENTS

Revenue from Contracts with Customers

Accounting Standards Update (ASU) 2014-09 was issued in May 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 along with 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.We have decided to adopt the revenue standard using the modified retrospective method.

We have reviewed our revenue contracts in order to evaluate the effect of the new standard on our revenue recognition practices. Based on our assessment, we do not anticipate any material differences in the amount or timing of revenue recognition under the new standard.

In addition, we are also in the process of implementing appropriate changes to business processes, systems and controls to support the recognition and disclosure requirements of the new standard and we have developed and tested processes to generate the new disclosures which will be required commencing in the first quarter of 2018.

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 investments 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. We do not expect the adoption of this accounting update to have a material impact on our Financial Statements.

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 agreements to recognize key lease assets and lease liabilities on the Balance Sheet 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. We are currently gathering a complete inventory of our lease contracts in order to assess the impact of the new standard on our Financial Statements. The accounting update is effective January 1, 2019 and will be applied using a modified retrospective approach.

Improvements to Employee Share-Based Payment Accounting

Effective January 1, 2017, we 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 our 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. We are currently assessing the impact of the new standard on our Financial Statements. The accounting update is effective January 1, 2020.

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 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. We have assessed the eight specific presentation issues and the adoption of this accounting standard does not have a material impact on our 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 changes in Restricted cash and restricted cash equivalents within the Statement of Cash Flows. The amendments require that changes in Restricted cash and restricted cash equivalents be included with Cash and cash equivalents when reconciling the opening and closing period amounts shown on the Statement of Cash Flows. We currently present the changes in Restricted cash and restricted cash equivalents under operating activities in the Statement of Cash Flows. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. We will amend the presentation in the Statement of Cash Flows to include restricted cash and restricted cash equivalents with Cash and cash equivalents and we will retrospectively reclassify all periods presented.

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 income statement presentation component and on a prospective basis for the capitalization component. We do not expect the adoption of this accounting update to have a material impact on our 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. We do not expect the adoption of this accounting update to have a material impact on our Financial Statements.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

We have established and maintained disclosure controls and procedures designed to provide reasonable assurance that: (a) material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Our management, with the participation of the President and Vice President, Finance, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2017, and, based upon this evaluation, the President and the Vice President, Finance have concluded that these disclosure controls and procedures, as defined by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109), are effective for the purposes set out above.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with U.S. GAAP. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, with the participation of our President and Vice President, Finance, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017 based on the framework in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting, as defined by NI 52-109, is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with U.S. GAAP.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Vice President, Finance, we have evaluated changes in internal control over financial reporting that occurred during the fiscal quarter and year ended December 31, 2017 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Our Board has reviewed and approved this MD&A and the attached audited Financial Statements prior to their release.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Union Gas' operations change and accounting guidance is issued. Union Gas has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Union Gas discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the Board.

Regulatory Accounting

The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers or for instances where the regulator provides current rates that are intended to recover costs that are expected to be incurred in the future. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non-regulated entities. We continually assess whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders to other regulated entities and the effect of competition. Based on this assessment, we believe our existing regulatory assets are probable of recovery. Total regulatory assets were $604 million as of December 31, 2017 and $557 million as of December 31, 2016. Total regulatory liabilities were $480 million as of December 31, 2017 and $430 million as of December 31, 2016.

Unbilled Revenue

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Gas sales and distribution revenue and gas commodity costs are recorded on the basis of regular meter readings and estimates of the unbilled customer usage. The unbilled estimate covers the period of the last meter reading date to the end of each month and is calculated using the number of days unbilled, heating degree-days and historical consumption per heating degree-day. Unbilled revenue recorded at December 31, 2017 was $202 million (2016 – $133 million) which was included in Accounts receivable and other on the Balance Sheets. Included in unbilled revenue are natural gas costs passed through to customers without a mark-up. At December 31, 2017 $116 million (2016 – $78 million) was included in unbilled revenue for the cost of natural gas.

Pension and Other Postretirement Benefits

The calculations of pension and other postretirement expense and liabilities require the use of numerous assumptions. Changes in these assumptions can result in different reported expense and liability amounts, and future actual experience can differ from the assumptions. We believe that the most critical assumptions used in the accounting for pension and OPEBs are the expected long-term rate of return on plan assets, the assumed discount rate and the medical and prescription drug cost trend rate assumptions.

Future changes in plan asset returns, assumed discount rates and various other factors related to the participants in our pension and postretirement plans will impact future pension expense and funding.

The expected return on plan assets is important since certain pension plans are funded. Expected long-term rates of return on plan assets are developed by using a weighted average of expected returns for each asset class to which the plan assets are allocated. For 2017, the assumed average return for the pension plan assets was 6.90%. The OPEB plans are not funded.

Since pension and OPEB costs and obligations are measured on a discounted basis, the discount rates used to determine the net periodic benefit cost and the benefit obligation are significant assumptions. Discount rates used for our defined benefit and OPEB plans are based on the yields constructed from a portfolio of high-quality bonds for which the timing and amount of cash outflows approximate the estimated payouts of the plans. A discount rate of 3.81% was used to calculate the 2017 net benefit cost, and represents a weighted average of the applicable rates. A discount rate of 3.53% was used to calculate the 2017 year-end benefit obligation and represents a weighted average of the applicable rates. The weighted average discount rate used to determine the benefit obligation decreased approximately 0.28% during 2017. The decrease in the benefit obligation discount rate and actuarial experience during 2017 resulted in an increase in benefit obligation at December 31, 2017 compared to December 31, 2016.

The following sensitivity analysis identifies the impact on the December 31, 2017 Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension		**OPEB**	
($millions)	Obligation	Expense	Obligation	Expense
Decrease in discount rate	64	5	5	—
Decrease in expected return on assets	—	4	N/A	N/A
Decrease in rate of salary increase	(9)	(2)	—	—

Asset Retirement Obligations

There is considerable judgment and measurement uncertainty in determining the value of the asset retirement obligations, Union Gas must estimate such factors as timing of settlements and abandonment or remediation costs. These estimates require extensive judgment about the nature, cost and timing of the settlement. Any changes in the estimates can impact the Asset retirement obligations and Property, plant and equipment, net. To arrive at the timing of settlements of abandoning pipelines, Union Gas uses historical results to predict future costs and other significant inputs into the calculation.

The Financial Statements and all information in this report have been prepared by and are the responsibility of management. The Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States of America and include certain estimated amounts, which are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon Union Gas Limited's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization. Management is also supported and assisted by a program of internal audit services.

The Board of Directors (the Board) is responsible for ensuring that management fulfils its responsibility for financial reporting and for final approval of the Financial Statements.

The Board meets regularly with management, the internal auditors and the shareholders' auditors to review the Financial Statements, the Independent Auditor's Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities.

The shareholders' auditors have full and free access to the Board, as does the Director of Internal Audit Services.

PricewaterhouseCoopers LLP performed an independent audit of the 2017 Financial Statements, as described in their Independent Auditor's Report.

Deloitte LLP performed an independent audit of the 2016 Financial Statements, as described in their Independent Auditor's Report, included in the 2016 Annual Report.

February 16, 2018

Stephen W. Baker	Wendy H. Zelond
President	Vice President, Finance

pwc

February 16, 2018

Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying financial statements of Union Gas Limited, which comprise the balance sheet as at December 31, 2017 and the statement of operations and comprehensive income, equity, and cash flows for the year then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements
Management is responsible for the preparation and fair presentation of these 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 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 financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the 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 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 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

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2017 and its results of operations and its cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Other matter
The financial statements at December 31, 2016 and for the year then ended, were audited by another auditor who expressed an unmodified opinion on those consolidated financial statements in their report dated February 26, 2017.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the Years Ended December 31 ($millions)	**2017**	2016
Revenues		
Gas sales and distribution revenue	**1,873**	1,529
Storage and transportation revenue (note 11)	**363**	299
Other revenue	**24**	21
Total Revenues	**2,260**	1,849
Expenses		
Gas commodity, storage and transportation costs (note 11)	**1,070**	738
Operating and maintenance (note 11)	**428**	414
Depreciation and amortization	**265**	239
Property taxes and other	**75**	71
Total Expenses	**1,838**	1,462
Income before interest and income taxes	**422**	387
Interest expense (notes 11 and 12)	**171**	161
Income before income taxes	**251**	226
Income tax expense (note 6)	**16**	21
Net income	**235**	205
Preferred shares dividends	**3**	3
Net income applicable to common shares	**232**	202
Other comprehensive loss, net of tax		
Pension and benefits impact (net of tax of (3) and (3) respectively) (note 15)	**(9)**	(7)
Comprehensive income applicable to common shares	**223**	195

The accompanying notes are an integral part of these Financial Statements.

BALANCE SHEETS

As at December 31 ($millions)	**2017**	2016
Assets		
Current assets		
Cash and cash equivalents	**19**	27
Restricted cash (note 3)	**13**	15
Accounts receivable and other (notes 2, 4 and 11)	**759**	801
Income taxes receivable (note 6)	**38**	29
Inventories (note 2 and 5)	**163**	245
Total current assets	**992**	1,117
Property, plant and equipment, net (note 7)	**6,913**	6,426
Intangible assets, net (note 8)	**368**	82
Regulatory and other assets (notes 2 and 9)	**643**	602
Total Assets	**8,916**	8,227
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 11)	—	253
Commercial paper (note 12)	**485**	333
Accounts payable and accrued charges (notes 10 and 11)	**730**	878
Current maturities of long-term debt (note 12)	**400**	125
Total current liabilities	**1,615**	1,589
Long-term liabilities		
Long-term debt (note 12)	**3,393**	3,295
Deferred income taxes (note 6)	**564**	516
Asset retirement obligations (note 16)	**399**	417
Regulatory and other liabilities (notes 2 and 9)	**884**	602
Total long-term liabilities	**5,240**	4,830
Total Liabilities	**6,855**	6,419
Preferred Shares (note 13)	**110**	110
Equity		
Common shares, unlimited shares authorized, 57,822,650 outstanding (note 14)	**657**	627
Retained earnings	**1,485**	1,253
Accumulated other comprehensive loss	**(195)**	(186)
Paid-in capital	**4**	4
Total Equity	**1,951**	1,698
Total Liabilities and Equity	**8,916**	8,227

The accompanying notes are an integral part of these Financial Statements.

Approved by the Board

Director | Director

STATEMENTS OF CASH FLOWS

For the Years Ended December 31 ($millions)	**2017**	2016
Operating Activities		
Net income	**235**	205
Items not affecting cash		
Depreciation and amortization	**268**	239
Loss on disposal of assets	**—**	1
Deferred income taxes	**(17)**	8
Changes in working capital (note 20)	**238**	(14)
Net cash provided by operating activities	**724**	439
Investing Activities		
Additions to property, plant and equipment	**(725)**	(1,012)
Additions to intangibles	**(305)**	(24)
Net cash used in investing activities	**(1,030)**	(1,036)
Financing Activities		
Net (decrease) increase in short-term borrowings	**(253)**	197
Net increase in commercial paper	**152**	126
Long-term debt issued, net of issue costs	**497**	499
Long-term debt repayments	**(125)**	(200)
Capital contribution received	**30**	—
Dividends paid	**(3)**	(3)
Net cash provided by financing activities	**298**	619
Change in cash and cash equivalents, during the year	**(8)**	22
Cash and cash equivalents, beginning of year	**27**	5
Cash and cash equivalents, end of year	**19**	27
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest, net of amounts capitalized	**169**	158
Cash payments of income taxes, net of refunds received	**34**	9
Property, plant and equipment noncash accruals	**9**	24

The accompanying notes are an integral part of these Financial Statements.

STATEMENTS OF EQUITY

($millions)	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Paid-in Capital	Total
December 31, 2016	627	1,253	(186)	4	1,698
Net income	—	235	—	—	235
Other comprehensive loss	—	—	(9)	—	(9)
Capital contribution received (note 14)	30	—	—	—	30
Dividends					
Preferred shares	—	(3)	—	—	(3)
December 31, 2017	657	1,485	(195)	4	1,951
December 31, 2015	627	1,051	(179)	4	1,503
Net income	—	205	—	—	205
Other comprehensive loss	—	—	(7)	—	(7)
Dividends					
Preferred shares	—	(3)	—	—	(3)
December 31, 2016	627	1,253	(186)	4	1,698

The accompanying notes are an integral part of these Financial Statements.

UNION GAS LIMITED
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2017 AND 2016

1. Summary of Operations and Significant Accounting Policies

The terms "Union Gas" or "the Company" as used in these Financial Statements refer to Union Gas Limited unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. Union Gas' common shares are held by Great Lakes Basin Energy L.P. (GLBE), a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

On February 27, 2017 Enbridge Inc. (Enbridge) and Spectra Energy completed a stock-for-stock merger transaction (the Merger) pursuant to which Enbridge acquired all of the issued and outstanding common shares of Spectra Energy. As a result of the Merger, Enbridge and its subsidiaries own Union Gas through their ownership of Spectra Energy.

Nature of Operations

Union Gas owns and operates natural gas distribution, storage and transmission facilities in Ontario. The Company distributes natural gas to customers in northern, southwestern and eastern Ontario and provides natural gas storage and transportation services for other utilities and energy market participants. The property, plant and equipment of the Company consist primarily of pipeline, storage and compression facilities used in the distribution, storage and transportation of natural gas.

Basis of Presentation

The Financial Statements of the Company include the standalone accounts of the Company and have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). All amounts are presented in millions of Canadian dollars except where 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.

Use of Estimates

The preparation of the Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities. Significant estimates and assumptions used in the preparation of the Financial Statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities; unbilled revenues; depreciation rates and carrying value of property, plant and equipment; amortization rates and carrying value of intangible assets; fair value of financial instruments; provisions for income taxes; assumptions used to measure retirement and Other Postretirement Benefits (OPEB); commitments and contingencies; and fair value of Asset Retirement Obligations (ARO). Actual amounts could differ from these estimates.

Regulation

The Company is regulated by the Ontario Energy Board (OEB) pursuant to the provisions of the *Ontario Energy Board Act, (1998)*, which is part of a package of legislation known as the *Energy Competition Act, (1998)*. This legislation provides an opportunity for different forms of regulation and increased competition in the energy (electricity and natural gas) industry in Ontario. The Company is subject to regulation with respect to the rates that it may charge its customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within the Company and provides the framework required to support new storage investments.

The OEB is mandated to approve rates that are just and reasonable. Utility earnings are regulated by the OEB under cost of service regulation, on the basis of a return on rate base for a future period. Under cost of service regulation, a rate application process leads to the implementation of new rates intended to provide a utility with the opportunity to earn an allowed rate of return. The actual rate of return achieved by the Company may vary from the rate allowed by the OEB as a result of unexpected changes in weather, average use per customer, inflation, the price of competing fuels, interest rates, general economic conditions and its ability to achieve forecasted revenues and manage costs.

Effective January 1, 2014, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings in excess of 100 basis points above the benchmark return on equity are shared with ratepayers as a reduction in earnings during the year, if applicable.

The Company follows U.S. GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under U.S. GAAP for non rate-regulated entities. Regulatory assets generally represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders to other regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate at the provincial and national levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered and collection is reasonably assured. Revenues related to these services provided or products delivered but not yet billed are estimated each month. 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.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume usage since the last meter reading date to the end of the reporting period applied using OEB approved rates. Cost of gas is recorded using amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred on the Balance Sheets for future disposition subject to approval by the OEB.

In determining the quantities of gas delivered and received, differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these differences based upon the methodology used by the OEB in the determination of rates for storage, transmission and distribution of gas. Annual fluctuations from the estimated level are recognized in earnings during the year.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Derivative Instruments and Hedging

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in currency exchange rates related to unregulated storage revenues. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded under Other comprehensive income/loss (OCI) and is reclassified to earning 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 is 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 Balance Sheet as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Statement of Cash Flows.

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. For the Company's regulated operations, a deferred income tax liability is recognized with a corresponding regulatory asset to the extent taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income tax expense.

Inventories

Gas in storage for resale to customers is carried at reference prices approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred on the Balance Sheets for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of average cost or net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment is stated at historical cost less accumulated depreciation and amortization. The Company capitalizes all construction-related direct labour and material costs, as well as indirect construction costs. Indirect costs include general engineering and the cost of funds used during construction. The costs of renewals and betterments that extend the useful life or increase the expected output of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment are expensed as incurred.

Regulated depreciation is computed based on the asset's average service life using the straight-line method. Unregulated depreciation is computed based on management's assumption of useful life using the straight-line method.

When regulated property, plant and equipment is retired, the original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation and amortization. When entire regulated operating units are sold or non-regulated property, plant and equipment is retired, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body.

Intangible Assets

Intangible assets consists of computer software and greenhouse gas (GHG) compliance instruments. The GHG compliance instruments are purchased by the Company for itself and most of its customers in order to meet Cap and Trade compliance obligations in the Province of Ontario (the Province). Purchased GHG compliance instruments are recorded at their original cost and are not amortized, as they will be used to satisfy compliance obligations as they come due. Computer software is amortized on a straight line basis.

Asset Retirement Obligations

The Company recognizes AROs for legal commitments associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset and conditional AROs in which the timing or method of settlement are conditional on a future event that may or may not be within the Company's control. The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made and is added to the carrying amount of the associated asset. This additional carrying amount is depreciated over the estimated useful life of the asset.

Stock-Based Compensation

Union Gas employees participate in a stock-based compensation plan sponsored by Enbridge, subsequent to the Merger. For employee awards, equity-classified and liability-classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is re-measured at each reporting period until settlement. Related compensation expense is recognized over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests, the date the employee becomes retirement-eligible, or the date the award market condition is met. Awards, including stock options, granted to employees that are already retirement-eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

Pension and Other 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 determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Net benefit 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 actual vs. expected plan experience, which include differences between the expected rate of return on plan assets and the actual rate of return for that period, differences in salary, inflation, retirement and termination experience. The actuarial gains and losses also include the impact of changes in the actuarial assumptions used to determine the accrued benefit obligation from one year end to the other.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

The Company also maintains supplemental pension plans that provide pension benefits in excess of the basic plans for certain employees.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides Postretirement benefits 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 Postretirement benefit plans is recognized as Regulatory and other assets, Accounts payable and accrued charges, or Regulatory and other liabilities on the Balance Sheets. 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, until they are amortized to be recognized as a component of benefit expense within Operating and maintenance expenses in the Statements of Operations and Comprehensive Income. See note 15 for further discussion.

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 probably loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

New Accounting Pronouncements

Revenue from Contracts with Customers

Accounting Standards Update (ASU) 2014-09 was issued in May 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 revenue 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 this assessment, the Company does not anticipate any material differences in the amount or timing of revenue recognition under the new standard.

In addition, the Company is in the process of implementing appropriate changes to business processes, systems and controls to support the recognition and disclosure requirements of the new standard and has developed and tested processes to generate the new disclosures which will be required commencing in the first quarter of 2018.

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 investments 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 Financial Statements.

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 agreements to recognize key lease assets and lease liabilities on the Balance Sheet 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 the Company's Financial Statements. The accounting update is effective January 1, 2019 and will be applied using a modified retrospective approach.

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 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 Financial Statements. The accounting update is effective January 1, 2020.

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 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 the eight specific presentation issues and the adoption of this accounting standard does not have a material impact on the Company's 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 changes in Restricted cash and restricted cash equivalents within the Statement of Cash Flows. The amendments require that changes in Restricted cash and restricted cash equivalents be included with 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 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 Statement of Cash Flows to include restricted cash and restricted cash equivalents with Cash and cash equivalents and the Company will retrospectively reclassify all periods presented.

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 income statement presentation component and on 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 Company's 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 Company's Financial Statements.

2. Regulatory Matters

Regulatory Assets and Liabilities

The Company recorded the following assets and liabilities that result from the regulated ratemaking process that would not be recorded under U.S. GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	**December 31, 2017**	December 31, 2016	Recovery/Settlement Period
Regulatory assets[a]				
Non-gas commodity deferrals	Accounts receivable and other	**74**	82	Less than 1 year
Gas in storage inventory[b]	Inventories	**—**	13	Less than 1 year
Deferred income taxes – long-term[c] [d]	Regulatory and other assets	**530**	462	Over the remaining life of the assets
Total regulatory assets		**604**	557	
Regulatory liabilities[a]				
Deferred income taxes – current[c]	Accounts payable and accrued charges	**7**	7	Less than 1 year
Non-gas commodity deferrals	Accounts payable and accrued charges	**16**	16	Less than 1 year
Gas cost deferrals[e]	Accounts payable and accrued charges	**4**	13	Less than 1 year
Gas in storage inventory[b]	Inventories	**21**	—	Less than 1 year
Asset removal costs[c] [f]	Regulatory and other liabilities	**432**	394	Over the remaining life of the assets
Total regulatory liabilities		**480**	430	

[a] All regulatory assets and liabilities are excluded from rate base unless otherwise noted.

[b] Gas in storage is recorded at reference prices approved by OEB. In the absence of rate-regulation, inventory would be valued at the lower of cost or market value.

[c] All or a portion of the balance is included in rate base.

[d] Under the current OEB-authorized rate structure, income tax costs are recovered in rates based on the current income tax payable and do not include accruals for deferred income tax. However, as income taxes become payable as a result of the reversal of timing differences that created the deferred income taxes, it is expected that rates will be adjusted to recover these taxes. Since substantially all of these timing differences are related to property, plant and equipment costs, recovery of these regulatory assets is expected to occur over the life of those assets.

[e] These regulatory liabilities represent gas cost collections from customers under approved rates that vary from the actual cost of gas for the associated periods. The Company files an application quarterly with the OEB to ensure that customers' rates are updated to reflect published forward-market prices. The difference between the approved and actual cost of gas is deferred for future repayment to or refund from customers.

[f] These regulatory liabilities represent collections from customers under approved rates for future asset removal activities that are expected to occur associated with its regulated facilities.

Rate Related Information

The Company's distribution rates, beginning January 1, 2014 are set under a five-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for:

- annual inflationary rate increases, offset by a productivity factor of 60% of inflation, such that the annual net rate escalator in each year is 40% of inflation,
- rate increases or decreases in the small volume customer classes where average use declines or increases,

- certain adjustments to base rates,
- the continued pass-through of gas commodity, upstream transportation and demand side management costs,
- the additional pass-through of costs associated with major capital investments and certain fuel variances,
- an allowance for unexpected cost changes that are outside of management's control,
- equal sharing of tax changes between the Company and its customers, and
- an earnings sharing mechanism that permits the Company to fully retain the return on equity from utility operations up to 9.93%, share 50% of any earnings between 9.93% and 10.93% with customers, and share 90% of any earnings above 10.93% with customers.

Annual Non-Gas Commodity Deferral Accounts Disposition

Non-gas commodity deferral accounts are filed for approval of disposition annually and typically collected or recovered over six months. In August 2017, the OEB approved collection of the 2016 non-gas commodity deferral account balances of $43 million beginning October 1, 2017.

Demand Side Management (DSM)

In December 2017, after receiving final audit results, the Company filed an application with the OEB for the disposition of the 2015 DSM deferral account balances. The impact is a net receivable from customers of approximately $8 million. Union Gas has requested a decision from the OEB in the first quarter of 2018 to allow recovery from customers to begin in the second quarter of 2018.

Application to Amalgamate

In November 2017, the Company and Enbridge Gas Distribution Inc. (EGD), 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, Union Gas and EGD 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 EGD. 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 Union Gas, EGD, and Enbridge's review and assessment of the regulatory outcomes and their respective Board of Directors approvals.

3. Restricted Cash

The Company had $13 million of restricted funds at December 31, 2017. At December 31, 2016, the Company had $37 million of restricted funds, with $15 million classified as Restricted cash and $22 million classified as Regulatory and other assets. These restricted funds are related to money received from the Province under the Green Investment Fund (GIF) program. The purpose of the GIF program is to reduce the GHG emissions in the residential sector. The Company's use of the funds is limited to eligible capital expenditures for the purpose of executing the program. The Company will manage the GIF program separately from its core regulated activities. There is no earnings impact relating to the GIF program. Any unspent funds must be returned to the Province at the expiry of the agreement on May 31, 2019, or should the Province elect to terminate the agreement at any time prior to is expiration date.

Changes in restricted balances are presented within Operating Activities on the Company's Statements of Cash Flows.

4. Accounts Receivable and Other

($millions)	**December 31, 2017**	December 31, 2016
Trade receivables	**209**	161
Unbilled revenue	**202**	133
Gas imbalances[a]	**251**	410
Regulatory assets – current	**74**	82
Other	**29**	20
Allowance for doubtful accounts	**(6)**	(5)
Total Accounts receivable and other	**759**	801

[a] The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

5. Inventories

Gas in storage includes gas for delivery to customers and for use in the Company's operations. Inventories of materials and supplies are for use in the Company's operations.

($millions)	**December 31, 2017**	December 31, 2016
Gas in storage	**140**	222
Materials and supplies	**23**	23
Total Inventories	**163**	245

6. Income Taxes

Income Tax Rate Reconciliation

($millions)	**2017**	2016
Income before income taxes	**251**	226
Canadian federal statutory income tax rate	**15.0%**	15.0%
Expected federal taxes at statutory rate	**38**	34
Increase (decrease) resulting from:		
Provincial income taxes	**—**	5
Part VI.1 tax, net of federal Part 1 deduction	**8**	5
Deferred income tax adjustments related to rate regulated operations	**(31)**	(25)
Other	**1**	2
Income tax expense	**16**	21
Effective income tax rate	**6.4%**	9.3%

Components of Pretax Earnings and Income Taxes

($millions)	**2017**	2016
Current income taxes	**33**	13
Deferred income taxes (recovery) expense	**(17)**	8
Income taxes expense	**16**	21

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 as follows:

($millions)	**December 31, 2017**	December 31, 2016
Deferred income tax liabilities		
Property, plant and equipment	**(445)**	(405)
Regulatory assets	**(139)**	(121)
Other	**(15)**	(22)
Total deferred income tax liabilities	**(599)**	(548)
Deferred income tax assets		
Pension	**35**	32
Total deferred income tax assets	**35**	32
Net deferred income tax liabilities	**(564)**	(516)

Unrecognized Tax Benefits

($millions)	**December 31, 2017**	December 31, 2016
Unrecognized tax benefits at beginning of year	**38**	28
Gross increases related to prior year tax positions	**7**	8
Gross decreases related to prior year tax positions	**(2)**	—
Gross increases related to current year tax positions	**3**	3
Reductions due to lapse of statute of limitations	**(1)**	(1)
Unrecognized tax benefits at end of year	**45**	38

The unrecognized tax benefits as at December 31, 2017, if recognized, would reduce the Company's annual effective income tax rate. Although uncertain, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $35 million prior to December 31, 2018. The anticipated changes in unrecognized tax benefits relate to the expiration of statutes of limitations and expected audit settlements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income taxes for the year ended December 31, 2017 included $nil (2016 – $nil) interest and penalties. As at December 31, 2017, interest and penalties of $1 million (2016 – $1 million) have been accrued.

The Company remains subject to examination for income tax returns for years 2009 through 2016.

7. Property, Plant and Equipment, net

($millions)	Useful Life (years)	**December 31, 2017**	December 31, 2016
Plant			
Natural gas transmission	20 - 58	**3,242**	2,734
Natural gas distribution	25 - 60	**4,887**	4,697
Storage	10 - 50	**1,187**	924
Land rights and rights of way	48 - 61	**141**	137
Other buildings and improvements	2 - 42	**63**	62
Equipment	4 - 15	**80**	82
Vehicles	6	**60**	57
Land	—	**94**	90
Construction in progress	—	**40**	349
Other	15 - 18	**17**	21
Total Property, plant and equipment		**9,811**	9,153
Total accumulated depreciation and amortization		**2,898**	2,727
Total Property, plant and equipment, net		**6,913**	6,426

The Company had no capital leases at December 31, 2017 or 2016.

96% of the Company's property, plant and equipment is regulated with estimated useful lives based on rates approved by the OEB. Composite weighted-average depreciation rates were 2.73% for 2017 and 2.76% for 2016.

The Company capitalized interest of $8 million in 2017 and $11 million in 2016.

8. Intangible Assets, net

($millions)	**December 31, 2017**	December 31, 2016
Intangible assets	**410**	116
Less: Accumulated amortization	**42**	34
Intangible assets, net	**368**	82

Intangible assets consists of computer software and GHG compliance instruments. As of January 31, 2017, GHG compliance instruments were purchased by the Company for itself and most of its customers in order to meet Cap and Trade compliance obligations in the Province. Purchased GHG compliance instruments are recorded at their original cost and are not amortized, as they will be used to satisfy compliance obligations as they come due. Computer software is amortized on a straight line basis over a period of 4 – 10 years.

The Company capitalized interest of $nil in 2017 and $1 million in 2016 related to software.

All of the Company's computer software was developed or obtained for internal use.

Amortization expense of intangible assets totaled $19 million in 2017 and $15 million in 2016. Estimated amortization expense for the next five years is as follows:

($millions)	2018	2019	2020	2021	2022
Estimated amortization expense	21	19	17	10	4

9. Regulatory and Other Assets and Liabilities

($millions)	**December 31, 2017**	December 31, 2016
Deferred income taxes – long-term (note 2)	**530**	462
Restricted cash	—	22
Goodwill	**12**	12
Pension assets	**33**	27
Balancing gas	**56**	67
Major spare parts	**10**	10
Other	**2**	2
Total Regulatory and other assets	**643**	602
Asset removal costs (note 2)	**432**	394
Pension liabilities	**167**	147
Unrecognized tax benefits	**45**	38
GIF payable	—	22
GHG compliance liabilities[a]	**238**	—
Other	**2**	1
Total Regulatory and other liabilities	**884**	602

[a] Under Cap and Trade regulation in the Province, the Company is required to meet GHG compliance obligations for most of its customers' use of natural gas as well as for emissions from its own operations. The Company will be required to relieve its compliance liability through the submission of compliance instruments following the completion of the initial compliance period of January 1, 2017 through December 31, 2020.

10. Accounts Payable and Accrued Charges

($millions)	**December 31, 2017**	December 31, 2016
Gas imbalances[a]	**251**	410
Accrued liabilities	**199**	170
Trade payables	**127**	142
Security deposits	**43**	39
Interest payable	**37**	37
Contractual holdbacks	**27**	34
Regulatory liabilities – current	**27**	36
Taxes payable	**19**	10
Total Accounts payable and accrued charges	**730**	878

[a] The Company, in the normal course of its operations, experiences imbalances in natural gas volumes between interconnecting pipelines and provides gas balancing services to customers. Natural gas volumes owed to or from the Company are valued at natural gas market prices as of the Balance Sheet dates. As the settlement of imbalances is done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

11. Related Party Transactions

The Company occasionally performs services for and incur costs on behalf of Enbridge, Spectra Energy and its affiliates (related parties), which are subsequently reimbursed. Likewise, certain related parties may perform services for or incur costs on behalf of the Company, which are then reimbursed by the Company. The Company also provides and purchases gas, storage and transportation services to related parties. These transactions are in the normal course of operations and are recorded at exchange amounts agreed to between the related parties.

In addition, related parties perform centralized corporate functions for the Company, pursuant to agreements with related parties, including legal, accounting, compliance, treasury, information technology and other areas, as well as certain engineering and other services. The Company reimburses related parties for the expenses to provide these services as well as other expenses they incur on the Company's behalf. Related parties charge such expenses based on the cost of actual services provided or using various allocation methodologies based on the Company's percentage of assets, employees, earnings or other measures, as compared to Enbridge and Spectra Energy's other related parties.

In the normal course of operations, the Company provides or obtains funds from Westcoast on an unsecured basis. The Company also has a promissory note to borrow up to $150 million from GLBE on an unsecured basis.

On July 31, 2017, the Company entered into a Gas Storage Service Agreement (GSSA) with EGD, a new affiliated company under common control as a result of the Merger, whereby the Company contracted all of EGD's unregulated storage space and deliverability effective September 2017. In conjunction with the GSSA, the Company entered into a Storage Contracts Assignment Agreement with EGD whereby the Company took assignment of EGD's customer contracts related to the assigned unregulated storage space, effective September 2017. On September 29, 2017, EGD novated all of its derivative instruments relating to foreign exchange forward contracts to the Company.

The Company's transactions with related parties are as follows:

($millions)	Storage and transportation revenue	Gas commodity, storage and transportation expense	Shared service charges (receipts)[a]	Total
2017				
St Clair Pipelines Partnership, a division of Westcoast	—	1	—	1
Pipeline and Field Services, a division of Westcoast	—	—	(4)	(4)
Westcoast Energy Inc.	—	—	(1)	(1)
Spectra Energy Gas Transmission LLC	—	—	12	12
Sarnia Airport Storage Pool Limited Partnership	(1)	5	—	4
Market Hub Partners L.P.	—	1	—	1
Enbridge Gas Distribution Inc.	(113)	7	—	(106)
Tidal Energy Marketing Inc.	(4)	—	—	(4)
Tidal Energy Marketing (US) LLC	—	5	—	5
St. Lawrence Gas Company Inc.	(1)	—	—	(1)
Express-Platte Pipeline L.P.	—	—	(1)	(1)
Total	(119)	19	6	(94)
2016				
St Clair Pipelines 1996, a division of Westcoast	—	—	(2)	(2)
Pipeline and Field Services, a division of Westcoast	—	—	(4)	(4)
Spectra Energy Empress L.P.	—	21	—	21
Spectra Energy Gas Transmission LLC	—	—	21	21
Sarnia Airport Storage Pool Limited Partnership	—	4	—	4
Total	—	25	15	40

[a]Excludes compensation arrangements.

Net amounts due from (to) related parties are as follows:

($millions), net	**2017**	2016
Enbridge Gas Distribution Inc.	**11**	—
Tidal Energy Marketing Inc.	**1**	—
Spectra Energy Gas Transmission LLC	**(4)**	(1)
Enbridge Inc.	**(2)**	—
Westcoast Energy Inc.	—	(253)
Other	**1**	—
Total[a]	**7**	(254)

[a]At December 31, 2017, $9 million (2016 – $5 million) is recognized in Accounts payable and accrued charges, $16 million (2016 – $4 million) is recognized in Accounts receivable and other, and $nil (2016 – $253 million) is recognized in Short-term borrowings on the Balance Sheets.

12. Debt and Credit Facilities

Summary of Debt and Related Terms

($millions)		**December 31, 2017**	December 31, 2016
9.70%	1992 Series II debentures, due November 6, 2017	—	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
2.76%	Series 11, due June 2, 2021	**200**	200
4.85%	Series 6, due April 25, 2022	**125**	125
3.79%	Series 10, due July 10, 2023	**250**	250
3.19%	Series 13, due September 17, 2025	**200**	200
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
2.81%	Series 14, due June 1, 2026	**250**	250
2.88%	Medium term note debentures, due November 22, 2027	**250**	—
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	300
4.20%	Series 12, due June 2, 2044	**500**	500
3.80%	Series 15, due June 1, 2046	**250**	250
3.59%	Medium term note debentures, due November 22, 2047	**250**	—
Long-term debt principal (including current maturities)		**3,815**	3,440
Less: Unamortized debt discount		**7**	7
Less: Debt issue costs		**15**	13
Add: Commercial paper		**485**	333
Total debt		**4,278**	3,753
Less: Current maturities of long-term debt		**400**	125
Less: Commercial paper		**485**	333
Total Long-term debt		**3,393**	3,295

The Company's long-term debt is unsecured. Principal repayment requirements on long-term debt are as follows:

($millions)	**Total**	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Long-term debt[(a)]	3,815	400	—	—	200	125	3,090

[(a)] Excludes commercial paper of $485 million.

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to several covenants including a limitation on the payment of dividends. As of December 31, 2017 and 2016, the Company is in compliance with all such covenants.

Total interest expense on long-term debt in 2017 was $171 million (2016 – $169 million).

Available Credit Facility and Restrictive Debt Covenants

($millions)	Expiration Date	Credit Facility Capacity	Commercial Paper Debt Outstanding at December 31, 2017	Commercial Paper Debt Outstanding at December 31, 2016
Multi-year syndicated [a]	2021	700	**485**	333

[a] The credit facility contains a covenant requiring the debt-to-total capitalization ratio, as defined in the agreement, to not exceed 75% and a provision which requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year. The ratio was 67.6% at December 31, 2017 (December 31, 2016 – 69.0%). Commercial paper issuances, net of discount, are back-stopped by the credit facility.

The available credit facility carried a weighted average standby fee of 0.085% on the unused portion.

The issuance of commercial paper, letters of credit and revolving borrowings reduce the amount available under the credit facility. As of December 31, 2017 and December 31, 2016 there were no letters of credit issued or revolving borrowings outstanding under the credit facility. The majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2017 was 1.28% (2016 – 0.87%). The weighted average days to maturity on outstanding commercial paper as of December 31, 2017 was fourteen days (2016 – 8 days).

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2017 and December 31, 2016, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower.

Total interest paid on short term debt in 2017 was $6 million (2016 – $1 million).

The Company and certain affiliates have, in aggregate, access to a $400 million demand letter of credit facility. As of December 31, 2017, the Company had no outstanding letters of credit under this facility.

13. Preferred Shares

	Authorized *(shares)*	Outstanding December 31, 2017 *(shares)*	Outstanding December 31, 2016 *(shares)*	December 31, 2017 *($millions)*	December 31, 2016 *($millions)*
Class A	202,072				
5.5% Series A		**47,672**	47,672	**3**	3
6% Series B		**90,000**	90,000	**5**	5
5% Series C		**49,500**	49,500	**2**	2
4.88% Class B, Series 10	Unlimited	**4,000,000**	4,000,000	**100**	100
				110	110

The Class A, Series A and Class A, Series C Preferred Shares are cumulative and redeemable at $50.50 per share. The Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable, but not exceeding $50 per share.

The Class A, Series B Preferred Shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preferred Shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares once every five years commencing

January 1, 2014. The holders of the Class B, Series 10 Preferred shares did not exercise their option on January 1, 2014 and their next optional conversion date is January 1, 2019. The Company may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2018.

The Company has an unlimited number of authorized 4.79% Class B, Series 11 Preferred Shares. These shares are cumulative and redeemable at $25 per share at the option of the Company, and at the option of the holders, convertible back into Series 10 shares, commencing on January 15, 2026 and on each fifth anniversary thereafter (each such anniversary, a Series 11 Conversion Date). Additionally, these shares are redeemable at $25.50 per share at the option of the Company on any date after January 15, 2026 that is not a Series 11 Conversion Date. At December 31, 2017 and December 31, 2016 none of these shares were issued or outstanding.

The shares are not subject to any sinking fund or mandatory redemption and are not convertible into any other type of securities other than Preferred shares. As these shares are not solely in the control of the Company, they have been classified as temporary equity on the Balance Sheets.

14. Share Capital

On January 31, 2017, the Company received a $30 million capital contribution from GLBE in respect of the Common shares of the Company. There were no Common shares issued as a result of this transaction.

15. Pension and Other Postretirement Benefits

Pension Plans

The Company maintains registered and non-registered, contributory and non-contributory pension plans which provide defined benefit and/or defined contribution pension benefits covering substantially all employees. The Company also maintains supplemental pension plans that provide pension benefits in excess of the basic plans 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. 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. The OPEB plans are not funded.

Benefit Obligation, Plan Assets 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	
($millions)	**2017**	2016	**2017**	2016
Change in benefit obligation				
Benefit obligation, at beginning of year	**917**	877	**61**	63
Service cost	**23**	19	**1**	1
Interest cost	**35**	35	**2**	3
Actuarial loss (gain)	**43**	22	**2**	(4)
Participant contributions	**4**	4	**—**	—
Benefits paid	**(43)**	(40)	**(2)**	(2)
Plan amendments	**—**	—	**(1)**	—
Benefit obligation, end of year [a]	**979**	917	**63**	61
Change in plan assets				
Fair value of plan assets, beginning of year	**854**	842	**—**	—
Actual return on plan assets	**73**	47	**—**	—
Benefits paid	**(43)**	(40)	**(2)**	(2)
Employer contributions	**16**	4	**2**	2
Participant contributions	**4**	4	**—**	—
Expected non-investment expenses	**—**	(3)	**—**	—
Fair value of plan assets, end of year	**904**	854	**—**	—
Underfunded status at end of year	**(75)**	(63)	**(63)**	(61)

	Pension		OPEB	
($millions)	**2017**	2016	**2017**	2016
Underfunded status at end of year				
Current Liabilities – Other	**(2)**	(2)	**(2)**	(2)
Deferred Credits and Other Liabilities – Regulatory and Other	**(106)**	(88)	**(61)**	(59)
Other Assets – Other	**33**	27	**—**	—
Underfunded status at end of year	**(75)**	(63)	**(63)**	(61)

[a] For pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. The accumulated benefit obligation for the Company's pension plans was $917 million as at December 31, 2017 (2016 – $866 million).

At December 31, 2017, pension plans with accumulated benefit obligations in excess of plan assets had projected benefit obligations of $574 million (2016 – $519 million), accumulated benefit obligations of $517 million (2016 – $475 million), and plan assets with a fair value of $466 million (2016 – $428 million).

Amounts Recognized in Accumulated Other Comprehensive Income (AOCI)

The amounts of pre-tax AOCI relating to the Company's pension and OPEB plans are as follows:

	Pension		OPEB	
($millions)	**2017**	2016	**2017**	2016
Net actuarial loss (gain)	**269**	257	**(4)**	(6)
Prior service cost	**1**	2	**(1)**	—
Total amounts recognized in AOCI, pre-tax	**270**	259	**(5)**	(6)

Net Benefit Costs 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	
($millions)	**2017**	2016	**2017**	2016
Net Benefit Costs				
Service cost	**23**	22	**1**	1
Interest cost	**35**	35	**2**	3
Expected return on plan assets	**(57)**	(57)	—	—
Amortization of actuarial loss and prior service cost	**15**	18	—	—
Net defined benefit and OPEB costs	**16**	18	**3**	4
Defined contribution benefit costs	**6**	6	—	—
Net benefit costs recognized	**22**	24	**3**	4
Amount recognized in Other Comprehensive Income				
Prior service cost	—	—	**(1)**	—
Net actuarial loss (gain) arising during the year	**26**	32	**2**	(4)
Amortization of actuarial loss and prior service cost	**(15)**	(18)	—	—
Total amount recognized in other comprehensive income	**11**	14	**1**	(4)
Total amount recognized in Comprehensive Income	**33**	38	**4**	—

The Company estimates that approximately $22 million related to pension plans and $nil related to OPEB plans at December 31, 2017 will be reclassified from AOCI into net income in the next 12 months.

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	
	2017	2016	**2017**	2016
Benefit Obligations				
Discount rate	**3.53%**	3.81%	**3.58%**	3.81%
Rate of salary increase	**3.04%**	3.00%	**3.22%**	3.00%
Net Benefit Costs				
Discount rate	**3.81%**	4.03%	**3.81%**	4.03%
Rate of salary increase	**3.00%**	3.00%	**3.47%**	3.00%
Rate of return on plan assets	**6.90%**	7.15%	**N/A**	N/A

Assumed Health Care Cost Trend Rates

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	**5.37%**	5.00%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	**4.36%**	5.00%
Year that the rate reaches the ultimate trend rate	**2034**	2017

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

($millions)	**1% Point Increase**	**1% Point Decrease**
Effect on total service and interest costs	**1**	—
Effect on accumulated postretirement benefit obligations	**2**	**(2)**

Plan Assets

Pension plan assets are maintained in a master trust. The investment objective of the master trust is to achieve reasonable returns on trust assets, subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants. The asset allocation targets were set after considering the investment objective and the risk profile with respect to the trusts. Equities are held for their high expected return. Other equity and fixed income securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the effects of individual managers or investments. The Company regularly reviews its actual asset allocation and periodically rebalances its investments to the targeted allocation when considered appropriate.

The asset allocation targets and major categories of plan assets are as follows:

Asset Category	**Target Allocation**	**December 31, 2017**	December 31, 2016
Equity securities	40%	**59%**	59%
Fixed income securities	45%	**41%**	41%
Other	15%	**—%**	—%
Total	100%	**100%**	100%

The following table summarizes the fair value of plan assets for the Company's pension plans recorded at each fair value hierarchy level, as determined in accordance with the valuation techniques described in note 17:

($millions)	Total	Level 1	Level 2	Level 3
December 31, 2017				
Cash and cash equivalents	4	4	—	—
Equity securities	532	249	283	—
Fixed income securities	368	368	—	—
Total	904	621	283	—
December 31, 2016				
Cash and cash equivalents	3	3	—	—
Equity securities	501	242	259	—
Fixed income securities	350	350	—	—
Total	854	595	259	—

Expected Benefit Payments and Employer Contributions

($millions)	2018	2019	2020	2021	2022	2023-2027
Pension	44	45	46	48	48	254
OPEB	2	2	3	3	3	16

In 2018, the Company expects to contribute approximately $20 million and $2 million to the pension plans and OPEB plans, respectively.

Retirement Savings Plan

In addition to the retirement plans discussed above, the Company also has defined contribution employee savings plans available to eligible employees. Employees may participate in a matching contribution where the Company matches a certain percentage of before-tax employee contributions of up to 5% of eligible pay per pay period. The Company expensed pre-tax employer matching contributions of $8 million in both 2017 and 2016.

16. Asset Retirement Obligations

The Company's AROs relate to the legal obligation to disconnect, purge and cap abandoned pipelines, capping abandoned storage wells, and in some buildings, special handling and disposition of asbestos if it is disturbed.

The Company has non-asbestos AROs which include easements and some railway license agreements relating to pipeline assets located on land which the Company does not own. The Company has not recognized a liability in regard to the non-asbestos ARO because the fair value of the ARO cannot be reasonably estimated. The Company's pipeline system is considered a critical component of its business and is expected to be maintained and remain in place indefinitely. Natural gas supplies are also considered sufficient for the Company to operate in the long-term.

AROs are adjusted each period for liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows.

Reconciliation of Changes in Asset Retirement Obligation Liabilities

The liability for the expected cash flows as recognized in the Financial Statements reflect discount rates ranging from 4.22% to 5.50% (2016 – 4.22% to 5.50%). A reconciliation of movements in the Company's ARO is as follows:

($millions)	**December 31, 2017**	December 31, 2016
Balance, beginning of year	**417**	440
Accretion expense	**19**	20
Liabilities incurred	**5**	7
Liabilities settled	**(8)**	(7)
Revisions in estimated cash flows	**(34)**	(43)
Balance, end of year	**399**	417

17. Risk Management and Financial Instruments

The Company's earnings, cash flows and OCI are subject to movements in natural gas prices and foreign exchange rates. Portions of these risks are borne by customers through certain regulatory mechanisms. Corporate risk management policies, processes and systems have been designed by the ultimate parent, Enbridge, to mitigate these risks.

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

Commodity Price Risk

Fluctuations in natural gas prices affect the Company's gas purchase costs for the Company's own operating requirements as well as for the gas supply costs the Company incurs for and collect from their system customers. The Company's gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. Commodity price volatility and absolute price levels also impact the amount of natural gas used by customers. Fluctuations in natural gas prices are borne by the customer in accordance with OEB directive.

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 denominated in U.S. dollars. As a result, the Company's earnings and cash flows are exposed to fluctuations resulting from U.S. dollars exchange rate variability.

During the third quarter of 2017, Union Gas took assignment of a number of EGD customer storage contracts, some of which were denominated in U.S. dollars. EGD also novated, to Union Gas, cash flow hedges that were used to manage exposure to changes in currency exchange rates in the assigned storage contracts.

Derivative Instruments

At December 31, 2017, the Company had approximately $1 million related to derivative instruments used as foreign exchange cash flow hedges (2016 – $nil), included in Accounts receivable and other and Regulatory and other assets. This amount is recorded at fair value as described below.

The Company's derivative instruments relating to foreign exchange forward contracts mature through 2023 and have a notional principal of $21 million (U.S. $17 million) (2016 – $nil).

Fair Value Measurements

Financial instruments recorded at fair value on the Balance Sheets are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1

Level 1 valuations represent quoted unadjusted prices for identical instruments in active markets.

Level 2 Valuation Techniques

Fair values of the Company's financial instruments that are actively traded in the secondary market are determined based on market-based prices. These valuations may include inputs such as quoted market prices of the exact or similar instruments, broker or dealer quotations, or alternative pricing sources that may include models or matrix pricing tools, with reasonable levels of price transparency. The fair value of the Company's pension plan assets designated as Level 2 financial instruments is determined through the market approach valuation technique using observable inputs including matrix pricing and market corroborated pricing. The fair value of foreign exchange contracts are also determined through the market value approach based on the extrapolation of observable future prices and rates. The fair value of other financial instruments relating to pension assets is disclosed in note 15.

Level 3 Valuation Techniques

Level 3 valuation techniques include the use of pricing models, discounted cash flow methodologies or similar techniques where at least one significant model assumption or input is unobservable. Level 3 financial instruments also include those for which the determination of fair value requires significant management judgment or estimation. The fair value of the Company's pension plan assets designated as Level 3 financial instruments is determined through the market approach valuation technique using unobservable inputs including investment manager pricing for private placements and private equities.

There were no transfers between levels during the year ended December 31, 2017.

Financial Instruments

The fair values of financial instruments that are recorded and carried at book value are summarized in the following table. Judgment is required in interpreting market data to develop the estimates of fair value. These estimates are not necessarily indicative of the amounts that could have been realized in current markets.

	December 31, 2017		December 31, 2016	
($millions)	**Book Value**	**Fair Value**	Book Value	Fair Value
Long-term debt, including current maturities[a]	**3,815**	**4,327**	3,440	3,888

[a] Excludes unamortized items.

The fair value of the Company's Long-term debt is determined based on market-based prices as described in the Level 2 valuation technique described above.

The fair values of Cash and cash equivalents, Accounts receivable and other, Accounts payable and accrued charges, Short-term borrowings and Commercial paper are not materially different from their carrying amounts because of the short-term nature of these instruments or because the stated rates approximate market rates.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligations. The maximum exposure to credit risk for the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

The Company, in the normal course of its operations, provides gas loans to other parties from its holdings of gas in storage. The replacement cost of gas loans at December 31, 2017 is $93 million receivable (2016 – $84 million receivable). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers, and obtaining collateral when appropriate.

The Company manages its credit risk on Cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on Accounts receivable, the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2017 amounted to $43 million (2016 – $39 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

Entering into derivative financial instruments may also result in exposure to credit risk. The Company has entered into risk management transactions with institutions that possess investment grade credit ratings.

The Company continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31, 2017**	December 31, 2016
Current	**386**	275
30 Days over due	**13**	10
60 Days over due	**4**	3
90+ Days over due	**8**	6
Total trade accounts receivable	**411**	294
Allowance for doubtful accounts	**(6)**	(5)
Total trade accounts receivable, net[a]	**405**	289

[a] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

For the years ended December 31, 2017 and 2016, no one customer accounted for more than 10% of sales or 10% of receivables.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 12).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2017:

($millions)	**Total**	**2018**	**2019-2020**	**2021-2022**	**Thereafter**
Commercial paper	485	485	—	—	—
Accounts payable and accrued charges	730	730	—	—	—
Long-term debt (including principal and interest)	6,503	570	294	607	5,032
Total	7,718	1,785	294	607	5,032

18. Stock Based Compensation

Until the close of the Merger, the Spectra Energy Corp 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provided for the granting of stock options, restricted and unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who performed services for Spectra Energy, including certain employees of Union Gas.

Performance and phantom awards granted under the 2007 LTIP typically became 100% vested on a three-year anniversary of the grant date. Options granted under the 2007 LTIP were issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, has ten-year terms and vested ratably over a three-year term.

Upon the close of the Merger or shortly thereafter, most Performance awards under the 2007 LTIP vested except for a portion of performance awards which were converted to 0.984 of Enbridge common stock that would time-vest at the end of 2018 if employment is continued. Likewise, Phantom awards were converted to 0.984 of Enbridge common stock that will vest as originally scheduled under the 2007 LTIP if employment is continued. The 2007 LTIP ceased after the Merger and qualified Union Gas employees may participate in a long-term incentive plan under Enbridge thereafter. There was no compensation expense recognized under a new long-term incentive plan under Enbridge in 2017.

Spectra Energy (and Enbridge after the Merger) allocated to Union Gas pre-tax stock-based compensation expense included in Operating Income for 2017 and 2016 as follows, the components of which are described further below:

Performance Awards

Under the 2007 LTIP, Spectra Energy granted stock-based performance awards. The performance awards generally vested over three years at the earliest, if performance metrics were met. The then unvested and outstanding performance awards granted previously contained market conditions based on the total shareholder return of Spectra Energy common stock relative to a pre-defined peer group. The equity-classified awards with market conditions were valued using the Monte Carlo valuation method.

Pre-tax compensation expense recorded by the Company for the years ended December 31, 2017 and 2016 for Performance awards were $2 million annually. The total fair value of the Performance awards vested was U.S. $6 million in 2017 and U.S. $1 million in 2016.

Phantom Awards

Under the 2007 LTIP, Spectra Energy also granted stock-based phantom awards. The phantom awards generally vested over three years. The liability-classified awards settled in cash at vesting. The liability-classified awards were remeasured at each reporting period until settlement.

Pre-tax compensation expense recorded by the Company for the years ended December 31, 2017 and 2016 for Phantom awards were $2 million annually. The total fair value of the Phantom awards vested was U.S. $1 million in 2017 and U.S. $1 million in 2016.

19. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Balance Sheets. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

20. Changes in Working Capital

($millions)	**December 31, 2017**	December 31, 2016
GHG compliance liabilities	**238**	—
Accounts receivable	**(114)**	(126)
Inventories	**19**	40
Accounts payable and accrued charges	**75**	35
Income tax receivable	**(9)**	(5)
Accumulated other comprehensive loss	**15**	19
Other	**14**	23
Total Changes in working capital	**238**	(14)

21. Commitments and Contingencies

Commitments

The table below is a summary of the Company's commitments, not otherwise disclosed in the Financial Statements, due by period.

($millions)	**Total**	**2018**	**2019**	**2020**	**2021**	**2022**	**Thereafter**
Operating leases	33	7	6	7	6	7	—
Purchase obligations[a]	2,407	509	260	213	165	146	1,114
Total commitments	2,440	516	266	220	171	153	1,114

[a] Includes: firm capacity payments that provide the Company with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; and contractual obligations for engineering, procurement and construction costs for pipeline projects. Due to a timing uncertainty, all procurement obligations have been included in 2018 as the Company is unable to reasonably estimate the payments due by period.

Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated.

In April 2016, the Ontario Ministry of the Environment and Climate Change (MOECC) issued a Director's Order (Order) naming the Company, along with other parties, as an impacted property owner in connection with a contaminated site adjacent to a property of the Company in Hamilton. In May 2016, the Company appealed the Order, and in June 2016, the Environmental Review Tribunal (Tribunal), on consent of the MOECC's Director, stayed the application of parts of the Order. The Tribunal has extended the stay of the Order several times, which has allowed the owner of the property (with the cooperation of the adjacent owners) to prepare a plan of action, including discussions with the MOECC and other neighbours (City of Hamilton and Infrastructure Ontario). The Company continues to monitor the matter, and to cooperate with the owner of the source property, the MOECC and other adjacent owners. The risk of material environmental liability is unknown at this time.

Other than the potential contingency noted above, of which the impact is unknown, the Company has no reason to believe that the ultimate outcome of these matters could have a significant impact on its Financial Statements.

Tax Matters

The Company maintains tax liabilities related to uncertain tax positions. While fully supportable in the Company's view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

DIRECTORS

Cynthia L. Hansen
Stephen W. Baker
David G. Unruh

OFFICERS

Stephen W. Baker
President

Cynthia L. Hansen
Chair and Executive Vice President, Utilities & Power Operations

Allen C. Capps
Controller

David G. Simpson
Vice President, Regulatory, Lands and Public Affairs

Tanya C. Mushynski
Vice President, Law

James G. Redford
Vice President, Business Development - Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael G.P. Shannon
Vice President, Distribution Operations

Wendy H. Zelond
Vice President, Finance

Sarah Van Der Paelt
Vice President, In-Franchise Sales, Marketing and Customer Care

Christopher G. Tuckwell
Assistant Controller

Wanda M. Opheim
Treasurer

Maximilian G. Chan
Assistant Treasurer

Tyler W. Robinson
Vice President and Corporate Secretary

David Taniguchi
Assistant Corporate Secretary

Kelly L. Gray
Assistant Corporate Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **AST Trust Company**

Union Gas Limited Preferred shares are listed on the Toronto Stock Exchange
Class A Preferred, Series A - 5½% (UNG.PR.C)

Class A Preferred, Series B - 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North
Chatham, Ontario N7M 5M1

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 3

Reference: Exhibit B, Tab 1, page 2

Question:
The evidence states that both utilities have limited individual opportunities to continue to deliver similar benefits (as those delivered by both utilities under their current and past incentive regulation frameworks) under a new five-year IR framework for rates. The evidence then states that the requested deferred rebasing period will allow the integrated utility to tackle larger, more complex system and processes, including Customer Care and Work Management Systems.

a) For each of Union and EGD, please provide a summary of the changes and improvements that were made to customer care and work management systems over the past 15 years under their respective IR frameworks.

b) What further improvements are Union and EGD expecting to make to customer care and work management systems under the IR framework going forward and explain in detail why a 10 year deferral period is needed to achieve this improvements.

Response

a) Both Union and EGD have made improvements in their customer care and work management systems over the past 15 years. Both organizations have a goal of continuous improvement. These improvements are typically targeted to improve efficiency, customer satisfaction, or both. The nature and summary of the changes and improvements that have been made over the past 15 years are too numerous to mention. However, a few indicative examples are provided below.

   One example of an improvement both Union and EGD have implemented is a customer portal that allows customers to view billing information and complete simple transactions online. Customers benefit from 24*7 access to the portal allowing them to interact when they choose and the contact centres benefit from increased efficiency by reducing the number of calls received.

   Other examples at Union include an online landlord portal to assist landlords in managing their various rental accounts, a mobile friendly customer portal that works well on cell phones and tablets, re-engineering of the customer move process and ongoing IVR (Interactive Voice Response) enhancements.

Similar to Union, EGD has made changes that have enhanced customers' ability to receive services, including bill delivery options, IVR enhancements and the introduction of online functionality to support the move process.

A significant example for EGD was the complete replacement of the work management system, which was completed in 2016.

b) Union and EGD have not started any detailed planning for its customer care or work management systems as part of the proposed amalgamation. The most significant improvement anticipated under the IR framework is the integration to a single platform for each of these systems. Additional information regarding the effort and estimated timelines associated with these activities can be found in the response to BOMA Interrogatory #16(d) found at Exhibit C.BOMA.16. Once in place Amalco would anticipate implementing continuous improvements to the new systems.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 4

Reference: Exhibit B, Tab 1, page 3

Question:
EGD and Union have been under common ownership for more than 1 year.

a) What savings have been achieved since the utilities have been under common ownership?

b) The utilities are proposing to merge effective January 1, 2019. Please explain why the merger was not contemplated for some time in 2018.

Response

a) Union and EGD have been operating as affiliates since February 27, 2017. No material cost savings have been achieved at the utility level as the utilities will not begin integration until the amalgamation is approved.

b) Union and EGD did not begin discussions on amalgamation until after the merger of Enbridge Inc. and Spectra Energy had been approved on February 27, 2017. Following approval of the corporate merger, Union and EGD worked on preparing the MAAD and Rate Setting Mechanism application and evidence which was filed in November 2017. This was an extremely aggressive timeline to file these two applications and as such, the earliest the amalgamation could take place was January 1, 2019 in order to allow time for the regulatory process to be completed and to internally seek approval of the Enbridge, Union Gas and Enbridge Gas Distribution boards to proceed.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 4

Reference: Exhibit B, Tab 1, Table 3 & 4

Question:
Table 4 shows the potential minimum and maximum increase in capital investment and the decrease in O&M.

a) Please confirm that the O&M savings and the increase in the capital expenditures would be included in the revenue requirement each year as shown in Table 3 on the Amalco line. If this cannot be confirmed, please explain fully.

b) Table 3 shows a cumulative ratepayer benefit of $410 million. Please add a column to Table 4 that reflects the assumptions related to incremental capital and OM&A savings that result in this level of benefit.

Response

a -b) Please see the evidence Exhibit B, Tab 1, page 21 through 23 for an explanation of the amounts contained in Table 3. Please see the responses to Energy Probe Interrogatory #8 and #9 found at Exhibit C.EP.8 and Exhibit C.EP.9 for further clarification.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 4

Reference: Exhibit B, Tab 1, page 25, Table 3 & Attachment 12

Question:

Attachment 12 shows the projected incremental capital investment and high level estimated O&M savings associated with utility integration for each year in the 2019 through 2028 period.

a) Please explain how the cumulative increase in capital investment of $150 million and the OM&A savings of $680 million in Attachment 12 relate to the $410 million in ratepayer benefits projected by Union in Table 3.

b) Please add two lines to the table in Attachment 12 that shows that increase/decrease in the revenue requirement for each year shown and the cumulative increase/decrease in the revenue requirement for each year shown.

Response

a) The estimated cumulative capital investment amount of $150 million and the O&M savings amount of $680 million shown in Attachment 12 are not related to the $410 million of projected ratepayer benefits shown in Table 3. An explanation of the estimated range of capital investment and O&M savings that the amalgamated entity is likely to recognize over the 2019 to 2028 deferred rebasing period, is provided at Exhibit B, Tab 1, page 26, Table 4 along with high level estimates within those ranges provided in Attachment 12. An explanation of the $410 million of projected ratepayer benefits is provided in Exhibit B, Tab 1, pages 20 to 23.

b) The capital investment and O&M savings amounts provided in Attachment 12 are high level estimates of amounts which would arise during the amalgamation into a single entity during the 2019 to 2028 deferred rebasing period and are not amounts requested within a rate mechanism.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 5

Reference: EB-2017-0306 & EB-2017-0307

Question:
Please provide a comprehensive list of commitments to future action made by the utilities during their respective 2013-2018 incentive rate plans. For each item, please provide a full description of the commitment, along with a reference to where the commitment was made. Please also provide the status of the commitment and the plans to deal with the commitment during the proposed deferral period.

Response

The EGD commitments are shown in Appendices A, B, & C (Attachment 1). The Union commitments are shown in Attachment 2.

2015-2018 Rate Proceeding Commitments — Appendix A

2018 Rate Proceeding Commitments EB-2017-0086

Line	Item	Reporting Information	Timing	Status
1	Gas Supply	Unaccounted for Gas ("UAF") Report: - Continue to review and report on certain investigations as to its unaccounted-for-gas	Annual	Ongoing

2017 Rate Proceeding Commitments EB-2016-0215

Line	Item	Reporting Information	Timing	Status
2	Gas Supply	File ICF Study on Storage Requirements: - Report on Enbridge's future storage requirements and evidence to support	2018 Rate Proceeding	Complete & ongoing
3	Gas Supply	Review of Firm Transportation Requirements: - Examine whether it is appropriate to amend the current requirements to demonstrate firm transportation to underpin Direct Purchase and system gas deliveries	2018 Rate Proceeding	Complete
4	Direct Purchase / Gas Supply	Update to Heat Value: - Commencing July 2017 use the updated heat value for Gas Supply planning & Direct Purchase delivery obligations	2017 Fiscal Year	Complete
5	Company Information	Ontario Landed Reference Price: - Consultation to review the potential of moving to an Ontario Landed Reference Price, prior to the 2018 Rate Adjustment Application	2017 Fiscal Year	Complete
6	Cap and Trade	Cap and Trade Impacts on Volumes Forecast: - Provide evidence on the impact of the Ontario Government's climate change policies and associated Cap and Trade framework on volumes forecast	2018 Rate Proceeding	Complete

2016 Rate Proceeding Commitments EB-2015-0114

Line	Item	Reporting Information	Timing	Status
7	Gas Supply	Gas Supply Plan: - Provide outline of Gas Supply planning process	2017 Rate Adjustment Application	Complete

Dawn Delivery Transportation Service EB-2012-154 & EB-2014-0323

Line	Item	Reporting Information	Timing	Status
8		Dawn T-Service Consultative	2014 - 2017	Complete

2015-2016 ESM Proceeding Commitments — Appendix B

2016 ESM Proceeding Commitments EB-2017-0102

Line	Item	Reporting Information	Timing	Status
1	Company Information	Additional evidence related to Average Use True Up Variance Account ("AUTUVA"): - Baseload, Heatload, Customer Counts - Outline changes to Rebasing: methodology, parameters and/or assumptions, if applicable - Explanations to the AUTUVA balances since rebasing, if any changes made to calculation - Monthly forecast volumes and customer meters, including baseload and heatload	Annual	N/A
2	Gas Supply	Unaccounted for Gas ("UAF") Report: - Continue to review and report on certain investigations as to its unaccounted-for-gas - Evidence outlining steps taken to address any reduction in UAF	Annual	Ongoing

2015 ESM Proceeding Commitments EB-2016-0142

Line	Item	Reporting Information	Timing	Status
3	Direct Purchase / Gas Supply	Interruptible Distibution Services: - Consider and advise if any potential cost effective changes that would make service more attractable to customer and thereby potentially avoid incremental firm transportation capacity or other costs	2017 Rate Adjustment Application	Complete
4	Gas Supply	Storage Optimization Transactional Services: - Advise of any trends that are apparent in respect of these revenues and evidence detailing the separation of storage optimization responsibilities and activities as between utility and non-utility optimization storage accounts	2016 ESM Application	Complete
5	Gas Supply	Incremental Gas Storage: - Prior to developing or aquire incremental storage capacity provide analysis and justification for the need	Annual	Done in 2018 Rate Proceeding

2014 ESM Proceeding Commitments EB-2015-0122

Line	Item	Reporting Information	Timing	Status
6	Gas Supply	Incremental Gas Storage: - Study incremental storage for future years with the support of an external consultant to determine needs	Annual	Ongoing

Rate Order
Appendix D
EB-2012-0459
2014-08-22

Reporting Commitments 2014 to 2018 EB-2012-0459

Appendix C

Line	Item	Reporting Information	Filing Timing	Annual Stakeholder Meeting (prior to ESM filing)	Completed
1	Company Information	Company Operations Overview: - review yearly earnings, capital spend and key operating items of interest, SQR's - Explain Market Conditions - Changes and trends impacting Operations - Customer Surveys/Feedback	ESM / Def. & Var. Account disposition application	Yes	Yes - to date
2	Company Information	Year End Financial Results / Earnings info: - Revenue Sufficiency/Deficiency Schedules - Rate Base Schedules - Utility Earnings, Tax Schedules - Additional Information aligning to Section 12.1 of Union Gas Settlement EB-2013-0202	ESM / Def. & Var. Account disposition application	Yes	Yes - to date
3	Performance Measurement / Benchmarking	Performance Measurement Reporting: - Capital productivity progress report - O&M productivity progress report	ESM / Def. & Var. Account disposition application	Yes	Yes - to date
		Benchmarking Report Capital & O&M (ReBasing): - consultation and independent expert opinion to inform methodology for filing upon rebasing	Rebasing 2019	Yes	Total Cost TFP Study filed in MAAD's appl.
4	Capital	Annual Capital Management Report: - Asset Planning Update: Progress in Asset Plan improvement with 3rd party assessment - GTA Project (Actual Cost and Schedule vs Forecast) - WAMS Project (Actual Cost and Schedule vs Forecast) - Capital Expenditures Update (Actual vs Plan Spending) - System Integrity Capital	ESM / Def. & Var. Account disposition application	Yes	Yes - to date
5	Gas Supply	Gas Supply Memorandum: - Consistent with Union Gas April 2014 Gas Supply Plan memorandum - A summary of the current natural gas market situation - The results of the design day demand forecast with a discussion of the underpinning assumptions - An overview of the current gas supply portfolio - The identifaction of near term portfolio decisions and a description of how the Enbridge strategy for the specific portfolio decision conforms to the gas supply plannning principles - A summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g.RH-003-2011); physical infrastructure projects that will likely impact Enbridge; and the implications associated with gas supply basins	ESM / Def. & Var. Account disposition application	Yes	Yes - to date
6	Gas Supply	Monthly UDC Report: Use of new FT services and associated UDC, monthly storage targets, capacity assigned to third parties through UDC related "outright release", revenues generated	Monthly	No	Yes
7	Reporting and Record keeping Requirements	Filings that are relevant to the regulated utility such as SQRs and affiliate transaction reporting	Annual - April 30	No	Yes

Other Non-Reporting Obligations

8	Allocation of costs to Non-utility storage	Prepare necessary evidence and proposal in time for 2015 or 2016 application. Information to make an allocation of base pressure gas and LUF to Non-utility storage on a fully allocated basis and on a volumetric basis	2015 or 2016	No	Yes
9	Regulatory Cost Allocation Methodology	Consultation in 2014 or 2015 for review of 2013 and 2014 data	2015	No	Yes
10	Sustainable Efficiency Incentive Mechanism	Consultation in 2015 to stakeholder an acceptable model	2016	No	No
11	Site Restoration Costs	Enbridge to look at discount rate to be used and examine issue of establishment of segregated fund of site restoration collections.	Rebasing 2019	No	No

Union COS Directives and 2014-2018 Proceeding Commitments

Line	Item	Reporting Information	Status	Addressed
1	Bright to Owen Sound Dawn-Trafalgar Facilities Expansion Program EBLO 251	Union is directed to report in each rates case for the next 30 years, an update to the peak day volume forecast shown for 1996/1997 in Appendix A to its supplementary evidence. (see Exhibit B1, Tab 5 of EB-2011-0210).	will no longer be applicable in 2029	
2	2013 COS EB-2011-0210	File an expert, independent review of Union's gas supply plan, gas supply planning process and gas supply planning methodology prior to Union’s next rates proceeding.	complete	EB-2013-0109 Exhibit B, Tab 5
3		File evidence to support the allocation of Union North and Union South Distribution Maintenance - Equipment on Customer Premises costs to rate classes in proportion to the allocation of customer station gross plant, including a definition for this maintenance category and a delineation of what has changed since EB-2005-0520.	at rebasing	EB-2013-0365 Exhibit A, Tab 1 - states Union has not completed a 2014 cost study given the Board's approval of the 2014-2018 IRM - 2019 Rebasing is the target proceeding to respond
4		Undertake a review of the allocation of Kirkwall metering costs as part of Union’s updated cost allocation study. Note: EB-2013-0365 Decision ordered Union to adjust the Kirkwall Station cost allocation methodology to take into account all volumes flowing through the Kirkwall metering station and allocate costs based only on demand.	complete	EB-2013-0365 Decision required adjustment for rates effective January 1, 2015 - Directive addressed EB-2014-0271 Exhibit A, Tab 1 (Updated)
5		File up to date continuity schedules related to Union's non-utility storage business.	complete	EB-2014-0145 Exhibit A, Tab 2, Appendix C, Schedules 1-3
6		Hire an independent consultant to update the Review of Cost Allocation for Unregulated and Regulated Storage Operations report filed in EB-2011-0038 (Black & Veatch Report) as part of its 2014 rates filing.	complete	EB-2013-0365 Exhibit A, Tab 2, Appendix A
7		Undertake a comprehensive cost allocation study which includes the M1/M2 and R01/R10 breakpoint reduction proposal no later than Union’s 2014 rates filing. The study is to include an analysis regarding the allocation of costs for Distribution Maintenance –Meter and Regulator Repairs related to the customers that would be moving rate classes.	complete	EB-2013-0365 Exhibit A, Tab 5
8		Prepare and file separate audited financial statements for the portion of the business that is subject to rate regulation no later than June 30th each year.	complete	EB-2013-0109 Evidence Addendum dated July 26, 2013 (Note: the Board in EB-2013-0109 Decision relieved Union of this Directive as the potential value of the separate statements did not justify the increased costs)
9		File sufficient evidence at the time the balance in the Short-term Storage Deferral account is to be disposed to allow the Board to confirm that Union has appropriately prioritized the sale of its utility storage space and calculated the balance in the account in accordance with the Board’s Decision.	complete	EB-2014-0145 Exhibit A, Tab 1
10		Communicate M4, M5A and M7 Changes to Customers.	complete	EB-2013-0365 Exhibit A, Tab 3
11		File a report relating to storage encroachment, similar to that ordered by the Board in EB-2011-0038 at the time the Short-term Storage Account is to be disposed.	complete	EB-2014-0145 Exhibit A, Tab 1
12		Report on the outcome of the Parkway Obligation Working Group.	complete	EB-2013-0365 Exhibit A, Tab 4
13		Establish a Working Group to review Union's Parkway Delivery Obligation and determine whether or not any changes should be made in whole or in part to that obligation after 2013.	complete	EB-2013-0365 Exhibit A, Tab 4 and EB-2013-0202 Settlement Agreement (Issue 13.3.2)
14		File a calculation for the payment by Union’s non-utility business to its utility business for storage encroachment, if any, at the time the Short-term Storage account is to be disposed.	complete	EB-2014-0145 Exhibit A, Tab 1

Union COS Directives and 2014-2018 Proceeding Commitments

Line	Item	Reporting Information	Status	Addressed
15	Settlement Agreement in Union's 2014 to 2018 Incentive Rate-setting Mechanism EB-2013-0202	Union agreed (subject to any subsequent agreement of all parties to extend the IRM term) to prepare a full cost-of-service filing at the time of rebasing, regardless of whether Union applies to set rates for 2019 on a cost-of-service basis or not.	at rebasing	
16		Parkway Delivery Obligation - In EB-2013-0202 Settlement Agreement (see Issue 13.3.2), Union confirmed a Working Group was formed. Union committed that should it and intervenors reach a consensus on an appropriate response to this review, Union will file with the Board a Settlement Agreement, together with supporting evidence, seeking approval of the agreed response in the 2014 rates proceeding. In the event a consensus is not reached, Union will file sufficient evidence on the issue and its position on whether or not any changes should be made to allow the Board to adjudicate the issue in the 2014 rates proceeding.	complete	EB-2013-0365 Exhibit A, Tab 4
17	Rate for interruptible LNG service at Hagar EB-2014-0012	Union was directed to file in the 2019 rebasing application a more robust and comprehensive cost allocation study that appropriately allocates costs for the new service.	at rebasing	
18	2014 Deferrals EB-2015-0010	Union filed its 2014-2015 Gas Supply Plan Memorandum (the Gas Supply Plan) as part of the evidence in the proceeding. Union agreed to provide an annual update to the gas supply plan as part of the settlement agreement in EB-2013-0202 (Union 2014-18 IRM Framework Application). Although Union did not seek any relief regarding the Plan, the proposed settlement agreement stated that there was no agreement on how or whether the OEB should deal with the Plan in this proceeding. (page 3)	ongoing	
19	Community Expansion EB-2015-0179	Union required to update the OEB within 90 days of the date of this Decision on the status of the Moraviantown project.	complete	Union filed status letter to OEB dated November 14, 2017
20	Dawn Reference and North T-Service EB-2015-0181	The OEB has therefore determined that any balances in the North T-Service deferral account be recovered from customers that have subscribed for the proposed service. Union is directed to communicate the decision of the OEB to all customers who have expressed interest in the new North T-service Transportation from Dawn service and to those who have already committed to the new service. The OEB further directs Union to provide to all customers who have subscribed for the service the right to opt out of the proposed service at no cost to the customer unless otherwise stipulated in their contract.	complete	
21	2015 Deferrals and 2015 Earnings Sharing EB-2016-0118	Agreed as part of settlement to file a study assessing the continued appropriateness of its methodology for determining the Normalized Average Consumption ("NAC"). Changes to NAC if appropriate will be considered as part of Union's 2019 rate proceeding.	at rebasing	
22		Union agreed as part of settlement to file evidence with more detail in 2016 Deferrals on the data centre co-location decision and its rationale.	complete	EB-2017-0091 Exhibit A, Tab 6
23	Union's 2017 Rates EB-2016-0245	Union agreed as part of settlement to report on the revenue neutrality of the new Customer Managed Service (CMS) and revisit the appropriateness of the service design at the time of its rebasing proceeding.	at rebasing	
24	2016 Dawn-Parkway Expansion Project EB-2014-0261	Parties agreed as part of settlement that the issue of Dawn Parkway capacity turnback post-2018 and how turnback risk should be dealt with in the context of the proposed facilities.	at rebasing	
25		The Board considers that the landowner should be entitled to decide if certain measures should be taken and directs this in the agreement Union offers to affected landowners.	complete	

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 5

Reference: EB-2017-0306 & EB-2017-0307

Question:
Please provide a complete list of other rate setting issues that the utilities believe merit attention now and indicate how and when these issues will be addressed.

Response:

The Applicants intend to propose changes to the cost allocation of Union's Panhandle System and St. Clair System (as described in the response to LPMA Interogatory #43(b) found at Exhibit C.LPMA.43) and to the rate design for Union's Rate M12/C1 transportation demand charges (as described in the response to TCPL Interrogatory #4 found at Exhibit C.TCPL.4) in the 2019 Rates application. The Applicants also intend to propose other administrative rate setting changes in the 2019 Rates application, such as combining Union's Rate M4 and Rate M5 onto one rate schedule and eliminating the Rate U2 rate schedule. Should any other rate setting issues be identified by the Applicants or stakeholders during the deferred rebasing period, they may be proposed as part of the annual rate adjustment application process or as part of a separate application.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

MAADs Issues List – Issue No. 6

Reference: Exhibit B, Tab 1, pages 10 & 40

Question:
The evidence states that Union has 95 BCF of storage space reserved for utility customers at cost-based rates.

a) Please confirm that the 95 BCF is equivalent to 100 PJ of storage.

b) Please explain fully how the merger of Union and EGD will impact the revenues and costs included in Account No. 179-70 Short-Term Storage and Other Balancing Services.

c) In the past Union has sold excess utility space (i.e. 100 PJ od in-franchise utility storage less the in-franchise utility requirement based on Union's gas supply plan) with 90% of the net revenue allocated to Union's ratepayers. How will this be impacted by the merger with EGD over the proposed deferral period?

Response

a) 100 PJ is approximately equal to 91 Bcf of storage space using Union's current South System Wide Average Heating Value (SWAHV) heat value of gas (38.95 $GJ/10^3m^3$). The reference in evidence should read 100 PJ.

b - c) The applicants are not proposing any changes to the sale of excess utility storage and deferral account treatment of the revenue obtained from the sale of excess utility storage as a result of the amalgamation.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, page 8

Question:

a) Please confirm that the use of GDP IPI FDD based on third quarter to second quarter figures from Statistics Canada is not consistent with the period used by the Board to determine the GDP IPI FDD used for electricity distributors.

b) Please confirm that the Board uses the most recent full year of data from Statistics Canada as the GDP IPI FDD figure for the following year. For example, in setting the increase in the GDP IPI FDD for 2019, the Board uses data for 2017.

c) What is the increase in the GDP IPI FDD for 2017 that would be applicable to 2019 if Amalco used the same time frame as used for electricity distributors?

Response

a) Confirmed. The proposed inflation factor for Amalco in 2019 is the GDP IPI FDD from Q3 2017 to Q2 2018. This approach is consistent with the approach currently used by Union in its 2013-18 IRM, but differs from the full year period used by electricity distributors.

b) Confirmed. As per the OEB December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379), the Board uses year-over-year change in the Canada Gross Domestic Product Implicit Price Index for final domestic demand [GDP-IPI (FDD)].

c) If the same time frame was used as electricity distributors, the calendar year 2017 GDP IPI FDD is 1.37% which is a decrease of 0.36% from the forecasted GDP IPI FDD of 1.73%. The actual Q3 2017 to Q2 2018 GDP IPI FDD proposed to be used to set 2019 rates will not be available until Q3 2018.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: EB-2017-0306, Exhibit B, Tab 1, page 3

Question:
The evidence states that amalgamation allows for greater operating efficiencies, including potential economies of scale as well as continuous improvement through best practices.

Please explain how the greater operating efficiencies, economies of scale and continuous improvement have been reflected in the proposed productivity factor.

Response

The reference material for the question talks about the prospect for greater operating efficiencies, including potential economies of scale, as well as continuous improvement through best practices. In that context, the question asks for an explanation of why such efficiencies and improvement are not in Dr. Makholm's proposed productivity factor (i.e., his X-factor or stretch factor).

Dr. Makholm addresses the answer from the perspective of the stretch factor considerations in Q/A 24 in his testimony, when he states:

> Of course, the consideration for merging utility operations take place in a complex context, and it would be a mistake to draw a straight line between incentive regulation and any particular utility merger. The extent to which anything associated with the change in regulatory regimes incentivized such a merger, is one of the salutary effects of the new [regulatory] regime. It is not the cause of heightened expectations that drive the stretch factor. It would a misuse of the stretch factor, as that term is commonly understood, to base it on any particular money-saving or efficiency-enhancing move by the utilities subject to the performance-based regime.

In other words, to the extent that the stretch factor is based on expectations coming with a changed regime (as confirmed by the AUC and by the consensus of the participating experts in its generic proceeding), there is no proper method for trying to anticipate merger savings through the stretch factor. (See Q/A 19 of Dr. Makholm's testimony for references to the AUC proceeding.

The same conclusion holds for the basic X-factor itself. As offered, both in this proceeding and in the generic AUC first PBR proceeding where he was the independent expert called by the AUC, Dr. Makholm's TFP growth study informing his X-factor recommendation stresses the paramount importance of objective uniformity and stability in the computation of the parameters of the PBR plan—particularly in the complex computations that lead to the X-factor. Such was confirmed by the AUC in its decision in that case, where it wrote as follows:

> Because the parameters of the PBR formula will be used to determine customer rates in a contested regulatory process and those rates will be in place for a number of years, the significance of the objectivity, consistency, and transparency of the TFP employed in calculating the X factor cannot be [over]stated. [note omitted] In this respect, the Commission observes that having extensively scrutinized and tested NERA's study, the companies were satisfied that NERA's TFP analysis complies with these criteria. [note omitted] The Commission agrees. (Alberta Proceeding 566, AUC Decision 2012-237, pp. 73-74)

There is no available method, under the type of regulation present in Canada and the United States to predict economies of scale or efficiency improvements to a standard that would meet the demands of the type of PBR formula to which the X-factor contributes. Therefore, while it is totally appropriate for the companies in this case to point to future operating efficiencies as an important reason for merging, such expectations do not meet the high standard of evidence required (i.e, the burden of proof), in North American regulation, to make a PBR formula. Thus, Dr. Makholm did not seek to estimate any such effects in his analysis.

Indeed, to the extent that the MAAD goals are involved, Dr. Makholm thinks that maintaining objectivity in the computation of the PBR formula remains of paramount importance. A credible long-term regulatory formula is central to meeting both goals of consumer protection (price stability, adequacy, reliability and quality of service) and industry health (access to capital markets, cost effectiveness and financial viability). (See Ontario Energy Board, "Handbook to Electricity Distributor and Transmitter Consolidations," January 19, 2016, pp. 6-10)

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 8-9

Question:
Please provide a table for each of EGD and Union for the 2013 through 2017 period that shows the approved ROE embedded in rates, the actual ROE, the normalized ROE and the effective X factor included in the respective incentive mechanisms.

Response

Please see Table 1 for Union's information and Table 2 for EGD's information.

Table 1
UNION GAS LIMITED

Line No.	Year	Board-approved ROE	Actual ROE	Weather-normalized ROE	X Factor
		%	%	%	%
1	2013	8.93	10.67 (1)	9.73 (6)	N/A (10)
2	2014	8.93	10.69 (2)	9.23 (7)	0.76 (11)
3	2015	8.93	9.89 (3)	9.46 (8)	1.23 (12)
4	2016	8.93	9.24 (4)	9.78 (9)	1.19 (13)
5	2017	8.93	9.15 (5)	9.54 (5)	1.00 (14)

Notes:

(1) EB-2014-0145, Exhibit A, Tab 2, p. 4
(2) EB-2015-0010, Exhibit A, Tab 2, p. 3
(3) EB-2016-0118, Exhibit A, Tab 2, p. 4.
(4) EB-2017-0091, Exhibit A, Tab 2, p. 3.
(5) Return on equity figures are expected to be included in the Application and Evidence for EB-2018-0105, but are draft at this time and may change.
(6) EB-2015-0010, Exhibit A, Tab 2, p. 1
(7) EB-2015-0010, Exhibit A, Tab 6, slide 7
(8) EB-2016-0118, Exhibit A, Tab 5, slide 7
(9) EB-2017-0091, Exhibit A, Tab 5, slide 5
(10) Not applicable due to Cost of Service
(11) EB-2013-0365, Rate Order, Working Papers, Schedule 1, line 6.
(12) EB-2014-0271, Rate Order, Working Papers, Schedule 1, line 6.
(13) EB-2015-0116, Rate Order, Working Papers, Schedule 1, line 6.
(14) EB-2016-0245, Rate Order, Working Papers, Schedule 1, line 6.

Table 2
ENBRIDGE GAS DISTRIBUTION

Line No.	Year	Board-approved ROE	Actual ROE	Weather-normalized ROE		X-Factor	
		%	%	%			
1	2013	8.93	11.13	10.41	(1)	N/A	(6)
2	2014	9.36	12.39	10.46	(2)	N/A	(6)
3	2015	9.30	10.41	9.82	(3)	N/A	(6)
4	2016	9.19	8.76	9.42	(4)	N/A	(6)
5	2017	8.78	9.71	10.27	(5)	N/A	(6)

Notes:
(1) EB-2012-0459, Exhibit J1.2
(2) EB-2015-0122, Exhibit B, Tab 5, Schedule 1
(3) EB-2016-0142, Exhibit B, Tab 5, Schedule 1
(4) EB-2017-0102, Exhibit B, Tab 5, Schedule 1
(5) Return on equity figures are expected to be included in the Application and Evidence for EB-2018-0131, but are draft at this time and may change.
(6) Not applicable to EGD as 2013 rates were set under Cost of Service, while 2014 - 2017 were set under Custom IR.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 10

Question:
The evidence states that the applicants are proposing to adjust rates annually to reflect the declining trend in use.

a) Please confirm that this reference is specific to the general use rate classes.

b) For each of the rate classes to which this statement applies, please provide a table that shows for the period 2008 through 2017 the normalized average use per customer based on the forecast normal degrees for each year.

c) For each of the rate classes to which this statement applies, please provide a table that shows for the period 2008 through 2017 the normalized average use per customer where the normalization for each year is based on the forecasted normal 2017 degree days.

d) Please explain what risks, if any, are faced by the applicants if there were no normalized average consumption/average use adjustments made, assuming the re-instatement of an LRAM for the general service rate classes.

Response

a) Confirmed. The average consumption adjustment applies to General Service/General Use rate classes.

b) Tables 1 and 2 follow for EGD and Union, respectively.

c) Tables 3 and 4 follow for EGD and Union, respectively.

TABLE 1 - EGD
GENERAL SERVICE AVERAGE USE

Test Year	Rate Classes	Col. 1 Actual Normalized Average Use (m^3)	Col. 2 Board-Approved Normalized Average Use (m^3)	Col. 3 Variance Normalized Average Use (1-2)	Col. 4 %Variance Normalized Average Use (3/2)*100
2008	Rate 1	2,636	2,647	(11)	-0.4%
	Rate 6	24,869	24,204	665	2.7%
	Total General Service	4,493	4,449	44	1.0%
2009	Rate 1	2,616	2,637	(21)	-0.8%
	Rate 6	27,654	28,165	(511)	-1.8%
	Total General Service	4,659	4,770	(111)	-2.3%
2010	Rate 1	2,579	2,622	(43)	-1.6%
	Rate 6	29,106	27,949	1,157	4.1%
	Total General Service	4,403	4,705	(302)	-6.4%
2011	Rate 1	2,594	2,643	(49)	-1.8%
	Rate 6	29,471	28,029	1,442	5.1%
	Total General Service	4,764	4,726	38	0.8%
2012	Rate 1	2,529	2,510	18	0.7%
	Rate 6	28,941	30,122	(1,182)	-3.9%
	Total General Service	4,642	4,715	(73)	-1.5%
2013	Rate 1	2,547	2,568	(22)	-0.8%
	Rate 6	29,878	29,878	(0)	0.0%
	Total General Service	4,665	4,719	(54)	-1.1%
2014	Rate 1	2,475	2,433	41	1.7%
	Rate 6	28,634	28,383	251	0.9%
	Total General Service	4,543	4,461	82	1.8%
2015	Rate 1	2,427	2,419	9	0.4%
	Rate 6	28,600	28,341	259	0.9%
	Total General Service	4,485	4,465	20	0.4%
2016	Rate 1	2,401	2,480	(79)	-3.2%
	Rate 6	28,203	28,753	(550)	-1.9%
	Total General Service	4,413	4,537	(124)	-2.7%
2017	Rate 1	2,485	2,472	13	0.5%
	Rate 6	29,462	29,058	404	1.4%
	Total General Service	4,572	4,538	34	0.7%

Table 2 - UNION GAS
GENERAL SERVICE NORMALIZED AVERAGE CONSUMPTION

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Actual NAC Former Rate M2 (m3)	(1)	4,271	4,182	4,103	4,209	4,090					
B.A. NAC Former Rate M2 (m3)	(2)	4,286	4,264	4,239	4,179	4,096					
Change	(3) = (2) - (1)	-15	-83	-136	30	-6					
% change	(4) = (3) / (2)	-0.3%	-1.9%	-3.2%	0.7%	-0.1%					
Actual NAC Rate M1 (m3)	(1)						2,768	2,748	2,676	2,667	2,764
B.A. NAC Rate M1 (m3)	(2)						2,778	2,751	2,761	2,852	2,738
Change	(3) = (2) - (1)						-10	-4	-85	-185	26
% change	(4) = (3) / (2)						-0.4%	-0.1%	-3.1%	-6.5%	0.9%
Actual NAC Rate M2 (m3)	(1)						169,422	167,537	163,129	159,933	166,969
B.A. NAC Rate M2 (m3)	(2)						143,867	165,085	169,121	172,693	166,297
Change	(3) = (2) - (1)						25,556	2,452	-5,992	-12,760	672
% change	(4) = (3) / (2)						17.8%	1.5%	-3.5%	-7.4%	0.4%
Actual NAC Rate 01 (m3)	(1)	3,252	3,213	3,175	3,190	3,186	2,900	2,923	2,799	2,788	2,835
B.A. NAC Rate 01 (m3)	(2)	3,153	3,128	3,128	3,128	3,109	2,765	2,898	2,901	3,015	2,844
Change	(3) = (2) - (1)	99	85	47	62	77	135	25	-102	-227	-9
% change	(4) = (3) / (2)	3.1%	2.7%	1.5%	2.0%	2.5%	4.9%	0.9%	-3.5%	-7.5%	-0.3%
Actual NAC Rate 10 (m3)	(1)	161,615	161,203	171,803	180,325	189,164	168,975	172,516	162,078	159,855	163,483
B.A. NAC Rate 10 (m3)	(2)	137,974	139,768	148,852	159,570	170,899	157,381	167,443	169,025	177,214	164,329
Change	(3) = (2) - (1)	23,641	21,436	22,951	20,755	18,264	11,594	5,073	-6,947	-17,359	-846
% change	(4) = (3) / (2)	17.1%	15.3%	15.4%	13.0%	10.7%	7.4%	3.0%	-4.1%	-9.8%	-0.5%

TABLE 3- EGD
GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Rate 1		2,710	2,680	2,619	2,568	2,559	2,538	2,534	2,512	2,421	2,485
	Change		(30)	(61)	(51)	(9)	(21)	(4)	(22)	(91)	64
	% Change		-1.11%	-2.28%	-1.95%	-0.35%	-0.82%	-0.16%	-0.87%	-3.62%	2.65%
Rate 6		25,531	27,394	29,514	29,468	29,332	29,096	29,313	29,641	28,480	29,462
	Change		1,863	2,120	(46)	(136)	(236)	217	328	(1,161)	982
	% Change		7.30%	7.74%	-0.16%	-0.46%	-0.80%	0.75%	1.12%	-3.92%	3.45%

* All historical average uses are on a calendar-year basis and have been normalized to the 2017 Budget degree days.

Table 4 - UNION GAS
GENERAL SERVICE NORMALIZED AVERAGE CONSUMPTION *

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Combined M1/M2		4,100	3,964	3,895	3,969	3,898					
	Change		-136	-68	74	-71					
	% Change		-3%	-2%	2%	-2%					
Rate M1							2,827	2,837	2,738	2,683	2,764
	Change							11	-99	-55	81
	% Change							0%	-3%	-2%	3%
Rate M2							172,351	171,956	166,297	160,693	166,969
	Change							-396	-5,658	-5,604	6,276
	% Change							0%	-3%	-3%	4%
Rate 01		3,074	2,994	2,959	2,965	2,969	2,946	2,994	2,844	2,797	2,835
	Change		-80	-34	6	4	-23	48	-150	-47	38
	% Change		-3%	-1%	0%	0%	-1%	2%	-5%	-2%	1%
Rate 10		150,758	147,593	155,601	162,779	170,875	171,225	176,072	164,329	160,271	163,483
	Change		-3,165	8,008	7,177	8,096	350	4,847	-11,744	-4,057	3,212
	% Change		-2%	5%	5%	5%	0%	3%	-7%	-2%	2%

d) The average use Y factors (deferral accounts) were established in recognition of the declining use environment brought about by conservation policies, DSM, and improvements in energy efficiency, and by the dynamic nature of forecasting the trend of these impacts. The Y factor adjustment protects ratepayers from over-recovery by utilities when actual usage is higher than anticipated, and protects utilities from under-recovery when actual usage is lower than anticipated. The use of these Y factors also better aligns the financial performance of the utility with conservation and climate change policy by eliminating the impact of non-weather related customer usage changes from the recovery of utility revenue requirement.

The reinstatement of LRAM for the general rate classes would serve to protect utilities from the impacts of their own DSM programs. With the renewed focus on climate change, Cap and Trade carbon pricing, and the ensuing abatement programs, the declining average consumption trend is not only expected to continue, but is expected to outweigh the impacts of DSM programs alone.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management (“LPMA”)

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 11-12

Question:

a) What is the current materiality threshold for Z factor purposes for each of EGD and Union?

b) Please explain why increasing interest rates would be considered a Z factor event given that the price of capital impact would be included in the GDP IPP FDD?

c) Did either of the utilities consider falling interest rates over the last 15 years of incentive regulation to be Z factor events? If not, why not?

d) Do the applicants believe they should be eligible for Z factors if they are over earning as a result of efficiencies gained through the merger that are not yet being shared with ratepayers? Please explain fully why ratepayers should be expected to pay more for unexpected changes when they do not benefit from unexpected increases in savings due to the merger.

Response

a) Please see the response to Board Staff Interrogatory#23 found at Exhibit C.STAFF.23.

b) See the response to Board Staff Interrogatory#17 found at Exhibit C.STAFF.17.

c) Over the past 15 years the 30 year Government of Canada Long Bond rate has declined in a slow and steady pace from near 5% to near 2%. This equates to approximately a 3% decline over the 15 years. Union Gas and Enbridge Gas operated for the most part of this 15 year period under multi-year incentive rate (IR) models where declining interest rates were part of the specific IR framework. The pace of interest rate changes and the related impacts did not result in the consideration of Z factor treatment.

   Savings that were generated from the decline in interest rates flowed through into the earnings sharing mechanism where applicable.

   Since 2013 interest rates have varied less than 1% which has not been a significant change.

EGD's Custom IR model has cost of debt reset each year during the term of 2013 to 2018. This has allowed ratepayers to benefit from debt refinancing under a lower interest rate environment.

Under Union's Price Cap mechanism, the expectation of falling interest rates was considered as part of accepting an X factor at 60% of inflation for the 2014-2018 period.

d) The applicants believe that any over earning resulting through the proposed 10 year deferred rebasing period would be a relevant consideration for eligible Z-factor determination by the Board.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 12-16

Question:
a) Please expand Table 1 to show the threshold percentages and values for each of EGD and Union for 2020 through 2028 assuming that the price cap index remains at 1.73% and the growth figure remains at 0.93% in each of the years.
b) Based on the most recent Asset Management Plans for each of EGD and Union, please provide the forecasted capital expenditures for each utility for each of 2019 through 2028.

Response

a) Please see table below for the threshold percentages and values for each of EGD and Union assuming price cap index and 1.73% and growth factor at 0.93% in each of the years.

Table A

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
ICM Threshold										
EGD										
Threshold value (%)	165%	166%	168%	169%	171%	172%	174%	176%	177%	179%
Threshold value ($)	503	507	512	517	521	526	531	537	542	548
UG										
Threshold value (%)	168%	170%	171%	173%	175%	176%	178%	180%	182%	184%
Threshold value ($)	330	333	336	339	342	346	349	353	356	360

b) Please see the response at FRPO Interrogatory #11(a) found at Exhibit C.FRPO.11. EGD forecast capital expenditures are on Table 1, line 3.1, and Union forecast capital expenditures are on Table 5, line 3.1.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 12-16

Question:
a) Please show the calculation of the growth factor of 0.93% for each of Union and EGD, showing all calculations and assumptions used.
b) Please explain why the growth factor is the same for Union and EGD.

Response

a) Please see Table 13 and Table 16 in the applicant response to FRPO Interrogatory #11(a) found at Exhibit C.FRPO.11.

b) The Illustrative ICM materiality threshold uses a simplified "g" factor, calculating the change in 2019 distribution revenues (Numerator) relative to 2018 distribution revenues (Denominator) for each utility separately. Both utilities are growing at approximately the same percentage. When Amalco files for the capital cost recovery of an ICM-eligible project, it will use the OEB's formula to determine the appropriate Numerator and Denominator used to calculate the actual "g" factor for each utility.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 12-16

Question:
For each of Union and EGD, please calculate the threshold percentage and value for each of 2014 through 2018 and then compare the threshold value to the actual capital expenditures in those years. For 2018, please use the forecasted level of capital expenditures.

Response

For 2014 to 2018, EGD set rates under a custom IR framework which does not permit any ICM. In order to perform such a calculation for EGD, various assumptions would have to be made regarding the inflation factor and the X factor implicit in a Price Cap formula, which are not resident within EGD's Custom IR.

For Union, capital pass through was subject to the capital pass through mechanism agreed to in the EB-2013-0202 Settlement Agreement. Actual capital expenditures relative to the ICM threshold is not relevant to 2014-2018, however the data is provided in the table below for information.

Illustrative 2013-2018 Union ICM Materiality Threshold

	$ Millions	**2013**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
		Board	Actuals					Forecast
(1)	Growth and Maintenance CapEx	268	316	322	339	343	353	443
(2)	Capital Pass Through Projects	80	52	155	352	691	368	115
(3)	Total Capital Expenditures	348	368	477	691	1,034	721	558
	ICM (Illustrative)							
(4)	ICM Materiality Threshold*	268	268	271	278	280	281	281
(5)	Total Capital Expenditures		368	477	691	1,034	721	558
(6)	**CapEx in excess of Threshold**		**100**	**206**	**413**	**754**	**440**	**277**
(7)	CapEx recovered through CPT		52	155	352	691	368	115
(8)	CapEx invested above Threshold and CPT		***48***	***51***	***61***	***63***	***72***	***162***

** ICM Materiality Threshold calculated as per Report of the OEB: EBO-2014-0219 New Policy Options for Funding for Capital Investments: Supplemental Report, January 22, 2016*

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 12-16

Question:

The evidence indicates that the applicants will be requesting approval of a rate adjustment to fund forecast incremental capital projects that qualify for ICM.

a) Will there be a true-up to reflect that each year the amount recovered through an ICM rate adjustment is not likely to equal the forecast due to variances in consumption levels and that the revenue requirement impacts of the ICM are likely to vary from that forecast? Please explain fully how all variances would be treated on a yearly basis and on a cumulative basis from one year to another.

b) Given that Union's existing capital pass-through mechanism is consistent with the Board's ICM, why are the applicants not proposing to continue to use this capital pass-through mechanism?

c) Does Union's existing pass-through mechanism reflect a revenue requirement to be recovered based on the last Board approved cost of capital parameters or on updated cost of capital figures? Please explain fully.

d) Under Union's existing pass-through mechanism, is Union guaranteed recovery of the revenue requirement that arises from actual costs, or is the recovered amount subject to fluctuations in revenue due to such drivers as warmer or colder weather? Please explain fully.

Response

a) Amalco will follow the Board's ICM policy, which calls for a true-up of the actual revenue requirement and the actual recovery of costs. Amalco will file the details of any proposed ICM deferral accounts as part of its 2019 rates application. Amalco expects to dispose of any balance in approved ICM deferral accounts as part of its annual non-commodity deferral disposition application.

b) Union's existing capital pass through mechanism was established as part of the EB-2013-0202 Settlement. It is not Board policy.

c) Union's existing capital pass-through mechanism uses the Board-approved capital structure of 36% equity and 64% long-term debt, with the equity portion at the Board-approved rate of return of 8.93%. The long-term debt rate used is the actual average long-term debt rate for debt that is issued in the year a project is placed into service.

d) No, under the current capital pass-through mechanism Union is not guaranteed full recovery of any actual revenue requirement. The forecast revenue requirements included in Board-approved rates for capital pass-through projects are subject to volume risk such as weather. Further, the deferral accounts for capital pass-through projects only record the variance between the forecast costs in rates and the actual costs of the projects.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, pages 12-16

Question:

a) Please explain why the applicants believe it is appropriate to deviate from the Board's required use of approved cost of capital parameters when calculating the revenue requirement.

b) Are the applicants aware of any change in the use of the approved cost of capital parameters for any electricity distributor that is in a deferred rebasing period as a result of a merger? If so, please provide details.

c) Please confirm that the Board's ICM policy is applied to rebasing deferral periods, regardless of length of the deferral period. If this cannot be confirmed, please explain fully.

Response

a) Please see the response to Board Staff Interrogatory #14 found at Exhibit C.STAFF.14.

b) No.

c) Confirmed.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.1

Reference: Exhibit B, Tab 1, page 30

Question:
Would any changes to accounting policy, such as the calculation of depreciation expense, or a change in depreciation rates, qualify as a Z factor adjustment, assuming it was material, related to the materiality threshold? If not, please explain why not.

Response

As noted in the response to Board Staff Interrogatory #31 found at Exhibit C.STAFF.31, accounting policy alignment/harmonization has not been completed at this time. As noted in EB-2017-0307, Exhibit B, Tab 1, harmonization in accounting practices resulting in material changes (if any) will be reported to the Board as part of the annual regulatory reporting process.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.2

Reference: Exhibit B, Tab 1, pages 20-22

Question:
Are the applicants proposing any penalties for failing to achieve any of the SQRs and/or performance metrics shown? If not, why not?

Response

No, the Applicants are not proposing penalties for failing to achieve SQRs and/or performance metrics or rewards for achieving or exceeding them. Please also see the response at VECC Interrogatory #43(b) found at Exhibit C.VECC.43.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.3

Reference: EB-2017-0306, Exhibit B, Tab 1, pages 9-10

Question:
At the end of 2016, EGD had approximately 2,100 employees and Union had approximately 2,300 employees.

How many employees did EGD and Union each have at the end of each of 2012, 2013, 2014, 2015 and 2017?

Response

Please see the response to CCC Interrogatory #7 found at Exhibit C.CCC.7.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.3

Reference: EB-2017-0306, Exhibit B, Tab 1, Table 1

Question:

a) Please update Table 1 to reflect actual data for 2017. If actual data for 2017 is not yet available, please update the table to reflect the most recent projections for 2017.

b) Please update Table 2 to include actual data for 2017. If actual data for 2017 is not yet available, please update the table to reflect the most recent projections for 2017.

Response

a) Please see Table 1 below.

Table 1
Comparison of Costs and Revenues as at December 31, 2017[1]

$ millions	EGD		Union		Combined
Rate Base	6,465	54%	5,474	46%	11,939
Operating Revenue	1,190	52%	1,088	48%	2,278
O&M	432	51%	414	49%	846
Customers	2,156,668	59%	1,474,944	41%	3,631,612

[1] EGD and Union 2017 utility results are not final, and have not been filed or approved with the OEB.

b) Please see Table 2 below.

Table 2
Comparison of O&M per Customer

	EGD			Union		
	O&M $ millions	Customers	O&M per Customer	O&M $ millions	Customers	O&M per Customer
2014[2]	408	2,063,837	198	380	1,419,499	268
2015[3]	431	2,094,681	206	383	1,436,924	267
2016[4]	450	2,124,683	212	398	1,458,720	273
2017[5]	432	2,156,668	200	414	1,474,944	281

[2] EGD O&M and customer numbers are filed in EB-2015-0122. Union O&M and customer numbers are filed in EB-2015-0010.
[3] EGD O&M and customer numbers are filed in EB-2016-0142. Union O&M and customer numbers are filed in EB-2016-0118.
[4] EGD O&M and customer numbers are filed in EB-2017-0102. Union O&M and customer numbers are filed in EB-2017-0091.
[5] EGD and Union O&M and customer numbers have not been filed with the OEB.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.4

Reference: Exhibit B, Tab 1, pages 26 & 8

Question:
Please confirm that if the Board directed Union to use the same time frame to calculate the GDP IPI FDD as it uses for the electricity sector, the annual rate adjustment application could be filed earlier than September 30.

Response

Confirmed.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.4

Reference: Exhibit B, Tab 1, page 26

Question:
Is the September filing date noted in the evidence driven by the use of the second quarter over second quarter GDP IPI FDD, which is not available until the end of August, or is there another reason for the September 30 date?

Response

The timing of the Q2 GDP IPI FDD data is the main reason for the filing in September.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.4

Reference: Exhibit B, Tab 1, page 26

Question:

a) Do the applicants envision separate filings for the setting of rates and the disposition of actual year-end non-commodity deferral account balances as is the current practice? If no, please explain.

b) Please list all components that would be included in the application to set rates, such as any Z factors, ICM requests, new regulated services, cost allocation and rate design changes, etc.

Response

a) The applicants will continue the current practice. To set rates and to clear non-commodity deferral account balances, Amalco will file individual applications that will address all three Rate Zones.

b) Please see the response to Board Staff Interrogatory#63 found at Exhibit C.Staff.63.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.4

Reference: Exhibit B, Tab 1, page 26

Question:
The evidence states that if ICM treatment of projects that will not be examined as part of a LTC application, the supporting documentation would be filed earlier than September 30.

a) Would any such request of ICM treatment be part of the annual rate adjustment filing, or a separate application?

b) Would any LTC project that triggers ICM treatment also be filed earlier than September 30?

Response

a) Please the response to Board Staff Interrogatory #63 at Exhibit C.STAFF.63.

b) Yes.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.5

Reference: Exhibit B, Tab 1, Attachment 4

Question:
a) Which of the deferral and variance accounts shown in Attachment 4 proposed for continuation would continue to be specific to either the Union or EGD franchise areas?

b) For each of the accounts shown in Attachment 4 which would no longer be specific to a franchise area, please explain the operation and allocation of balances in the account.

Response

a) As described in the response to SEC Interrogatory #45 found at Exhibit C.SEC.45, all of the deferral and variance accounts proposed for continuation, which are shown in Attachment 4, would continue to be specific to either the Union or EGD rate zones.

b) See response to part a).

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.6

Reference: Exhibit B, Tab 1, page 23

Question:
Please provide the 2017 actual year end balance and the projected 2018 year end balance for each of the accounts shown that are proposed to be eliminated.

Response

Please see Table 1 for the above noted deferral account balances. These are general ledger balances at December 31, 2017 and do not include any possible adjustments in 2018. Note, Union and Enbridge do not project deferral account balances, as such, 2018 balances are not provided.

Account Number	Account Name	Dec. 31, 2017 Balance Receivable / (Payable)*
EGD		
179-16_	Customer Care CIS Rate Smoothing Deferral Account	$5.121
179-34_	Constant Dollar Net Salvage Adjustment Deferral Account	$37.941
179-96_	Relocations Mains Variance Account	$0.000
179-98_	Replacement Mains Variance Account	$0.000
179-24_	Post-Retirement True-up Variance Account	($4.299)
179-58_	Earnings Sharing Mechanism Deferral Account	($23.700)
Union		
179-120	CGAAP to IFRS Conversion Costs	$0.000
179-134	Tax Variance Deferral Account	($0.292)

*Balances are shown in millions

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.7

Reference: Exhibit B, Tab 1, page 22

Question:

a) Please confirm that the applicants are not proposing any new deferral or variance accounts. If this cannot be confirmed, please explain what new accounts are being proposed.

b) The applicants propose to record any earnings sharing payable to ratepayers be recorded as a liability rather than in a deferral account. Will any such earnings sharing payable to ratepayers attract interest if they are recorded as a liability instead of in a deferral account?

Response

a) Confirmed. The applicants are not proposing any new deferral or variance accounts as part of EB-2017-0306/EB-2017-0307. However, the applicants may bring forward new deferral account proposals (e.g. for ICM) for Board approval as part of Amalco's 2019 rates application.

b) Yes, any earnings sharing balance in a liability account will attract interest at the same rate as deferral accounts.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management (“LPMA”)

Rate Setting Issues List – Issue No.8

Reference: Exhibit B, Tab 1, page 16

Question:
Union proposes to adjust 2019 rates to reflect the removal of the accumulated deferred tax balance credit to customers.

Please provide a list of all cost reductions that have taken place, or are forecast to take place, over the incentive regulation period of 2013 to 2018 that exceed the proposed materiality threshold of $1 million. Please quantify each of these reductions.

Response

As part of its 2014 to 2018 IRM Settlement Agreement, Union committed to a $4.5 million annual upfront productivity commitment. This commitment totals $22.5 million over the 5 year period. The X-factor of 60% from 2014 through 2018 also required Union to find a significant amount of capital and labour productivity to achieve its allowed rate of return on equity.

Union is not able to provide a list of all cost reductions that have taken place over its current incentive regulation period that may exceed the proposed materiality threshold of $1 million.

Since 2014, opportunities to implement large scale productivity improvements across the organization have not presented themselves. Rather, Union has undertaken numerous small scale process improvements, in order to manage cost increases and drive incremental productivity. These small initiatives and actions enabled the organization to manage within the context of a Price Cap Index from 2014 to 2018 that only provides for rate increases equal to 40% of inflation.

As described at EB-2017-0307, Exhibit B, Tab 1, page 16, the proposal to adjust 2019 rates for the removal of the accumulated deferred tax balance credit is due to the fact that ratepayers have received the full benefit of lower rates for 20 years (1999 through 2018) in relation to the drawdown of a deferred tax benefit. The 20 year benefit period was finite and was in relation to the natural reversal of depreciation expense and Capital Cost Allowance timing differences for periods in 1997 and prior for which the timing differences tax benefit / reduction is no longer available.

In 1997, Union changed its accounting for utility income taxes from the tax allocation (or accrual) method to flow-through (or cash-basis) tax accounting. This change was adopted for rate-making purposes on a prospective basis and approved by the Board in its E.B.R.O. 493/494 Decision. The tax allocation method of accounting used for rate-making purposes prior to E.B.R.O. 493/494 resulted in an accumulated deferred tax balance.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.8

Reference: Exhibit B, Tab 1, page 16

Question:

How does Union propose to allocate the increase in the Board-approved revenue of $17.4 million?

Response

Union proposes to allocate the $17.4 million base rate adjustment to Union rate classes in proportion to the 2013 Board-approved deferred tax drawdown benefit included in Union's 2018 Rates. The allocation of the $17.4 million adjustment by rate class is provided in Table 1.

Table 1

Allocation of Union's Deferred Tax Drawdown

Line No.	Particulars	Allocation (%) (1)	Allocation ($000's)
		(a)	(b)
	Union North		
1	Rate 01	3.2%	550
2	Rate 10	0.8%	144
3	Rate 20	0.2%	38
4	Rate 100	0.0%	3
5	Rate 25	0.0%	-
6	Total Union North	4.2%	735
	Union South		
7	Rate M1	39.4%	6,868
8	Rate M2	6.6%	1,144
9	Rate M4	1.8%	308
10	Rate M5	1.0%	174
11	Rate M7	0.6%	110
12	Rate M9	0.1%	23
13	Rate M10	0.0%	1
14	Rate T1	1.4%	247
15	Rate T2	7.0%	1,227
16	Rate T3	1.1%	192
17	Total Union South	59.0%	10,293
	Ex-Franchise		
18	Excess Utility Space	1.1%	197
19	Rate C1	0.2%	37
20	Rate M12	35.4%	6,168
21	Rate M13	0.0%	4
22	Rate M16	0.0%	7
23	Total Ex-franchise	36.8%	6,413
24	Total Union	100.0%	17,441

Notes:

(1) EB-2011-0210, Exhibit G3, Tab 2, Schedule 2, Updated per EB-2013-0365 Settlement Agreement (Accumulated Deferred Tax Drawdown Line).

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.9

Reference: Exhibit B, Tab 1, page 20

Question:
How does EGD propose to allocate the $4.9 million decrease in revenues?

Response

The proposed $4.9 million decrease in revenues to 2018 rates is associated with CIS and customer care costs. The Company would propose to allocate the $4.9 million decrease to customers in the same manner in which the costs for CIS and customer care are currently allocated to the customer classes and recovered in rates. Accordingly, the proposed decrease would be allocated to the customer classes based on customer numbers in each rate class.

The proposed approach would result in an approx. allocation of the $4.9 million decrease as shown in the table below:

Customer Class	Customer Count Allocation Factor	Customer Count Allocation Factor %	Total Allocated $ (millions)
Rate 1	2,015,077	0.9231	(4.52)
Rate 6	167,564	0.0768	(0.38)
Rate 9	0	-	-
Rate 100	0	-	-
Rate 110	265	0.0001	(0.00)
Rate 115	27	0.0000	(0.00)
Rate 125	4	0.0000	(0.00)
Rate 135	43	0.0000	(0.00)
Rate 145	36	0.0000	(0.00)
Rate 170	25	0.0000	(0.00)
Rate 200	1	0.0000	(0.00)
Rate 300 Firm	1	0.0000	(0.00)
Total	**2,183,043**	**1.0000**	**(4.90)**

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management (“LPMA”)

Rate Setting Issues List – Issue No.10

Reference: January 11, 2018 Evidence Addendum

Question:
All parties agreed in the EB-2017-0086 Settlement Proposal that EGD would recover the actual amount of its Pension and OPEB costs and related revenue requirement in 2018 through amounts to be recorded in the Post-Retirement True-Up Variance Account (“PTUVA”). As a result of legislative changes, the allowed revenue requirement for 2018 would be $6.5 million higher than currently built into rates. EGD proposes to adjust the 2019 allowed revenue requirement to reflect this change.

a) Is the $6.5 million increase in pension and OPEB costs a final amount, or could the increase fluctuate depending on market conditions, interest rates, etc.? Please explain fully.
b) Rather than incorporating the increase in base rates for 2019, did EGD consider the option of continuing the PTUVA over the 2019 to 2028 period? If not, why not?
c) Please explain the relevance of an allowed revenue requirement or changes to the allowed revenue requirement in 2019 when 2019 is proposed as the first year under a price cap incentive mechanism.
d) How does EGD propose to allocate the increase in costs?

Response

a) EGD’s proposal to adjust the 2019 Allowed Revenue requirement by an increase of $6.5 million is a final amount. As explained in the evidence addendum filed January 11, 2018, the $6.5 million increase reflects the Allowed Revenue amount that EGD had originally filed for 2018 pension and OPEB costs in its 2018 Rate Adjustment case (EB-2017-0086). This amount is reflective of the pension and OPEB analysis and forecast performed in 2017, which at the time assumed certain future market conditions and interest rates and anticipated legislative changes likely to be enacted in December 2017. The 2018 Rate Adjustment Settlement Agreement did not include the impact of the legislative changes, since those had not been finally enacted at that time. Since that date, the anticipated changes to the *Pension Benefits Act* have been enacted, and this results in a $6.5 million increase to EGD’s Allowed Revenue associated with pension and OPEB costs. No adjustment is made or planned in relation to any future fluctuations in market conditions and interest rates.

b) Consideration was given to continuing the PTUVA; however, a decision was made to remove the account in order to try to align the variance accounts between EGD and Union.

c) As seen in evidence in EB-2017-0307 (see Exhibit B-1, section 4 and January 11, 2018 evidence addendum), Enbridge has proposed limited adjustments to beginning 2019 rates to account for the fact that previously-approved smoothing mechanisms, refunds and deferral/variance accounts will no longer be in place for certain items. To this end, the proposed adjustments to the beginning 2019 rates generally relate to items which had drawdown, refund or smoothing type mechanisms attached to them over finite periods of time, ending in 2018.

   For clarity, please note that the proposed revenue requirement adjustment of $6.5 million will be applied to the Board-approved 2018 revenue requirement and, subsequently, 2018 rates. The adjusted 2018 rates will then be used as base rates for 2019 rate adjustment under a Price Cap rate setting mechanism.

d) Given that virtually the entire impact of the $6.5 million increase in Allowed Revenue (revenue requirement) to update for changes in pension legislation is reflected in income taxes on earnings, the Company proposes to allocate the $6.5 million increase in revenue requirement using the Rate Base allocator from 2018 Final Rate Order (EB-2017-0086, Exhibit G2, Tab 6, Schedule 3, Page 2, Item 5). This approach follows the Company's Board-approved cost allocation methodology where return and tax are allocated to the customer classes based on allocation of rate base to the customer classes.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.11

Reference: January 11, 2018 Evidence Addendum

Question:

a) Rather than increasing the allowed revenue requirement over the amount approved in EB-2017-0086, did EGD consider using the change in the tax deduction as a Z factor in the deferred rebasing period? If not, why not?

b) If there are other changes to tax deductions during the deferred rebasing period, would those changes be reflected in rates through a change to an allowed revenue requirement, or through the use of a Z factor? Please explain fully.

c) How does EGD propose to allocate the increase in costs?

Response

a -b) No consideration was given to a change in the tax deduction associated with the Site Restoration Cost necessary adjustment, as no tax deductibility exists beyond 2018 for this issue.

Additionally, as the lack of tax deductibility is known, such proposed treatment would not qualify as a Z factor. Changes to tax deductions relative to the types and levels of costs considered to be covered within the proposed Price Cap formula would not constitute appropriate adjustments to rates in either fashion.

c) Given that virtually the entire impact of $11.2 million related to the SRC tax deduction is reflected in income taxes on earnings, the Company would propose to allocate the $11.2 million increase in revenue requirement using the Rate Base allocator from 2018 Final Rate Order (EB-2017-0086, Exhibit G2, Tab 6, Schedule 3, Page 2, Item 5). This approach follows the Company's Board-approved cost allocation methodology where return and tax are allocated to the customer classes based on allocation of rate base to the customer classes.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.12

Reference: Exhibit B, Tab 1, page 29

Question:

a) Please provide the applicants understanding of the provisions of the MAADs Handbook related to harmonization.

b) Do the applicants have any plan, at this time, to harmonize rates at the end of the deferred rebasing period?

c) Please provide a table that shows, based on current 2018 distribution rates, the revenue collected from the following types of customers: an average M1 residential customer, an average M1 commercial customer, a small M2 customer, a large M2 customer and a small M4 customer in Union South and in the EGD franchise. Please use average volumes based on Union Gas figures for annual consumption in the comparison and indicate the EGD rate that was used for each of the types of customers.

Response:

a) Union and EGD understand, as per the Board's handbook for consolidations, that a consolidated entity is expected to propose rate structures and rate harmonization plans following consolidation at the time it files its rebasing application. The Board will review and address rate harmonization plans at the time of rate rebasing of the consolidated entity.

b) Union and EGD have not developed a plan to harmonize rates.

c) Please see Attachment 1.

UNION GAS LIMITED & ENBRIDGE GAS DISTRIBUTION

Calculation of Total Bill for Union and Enbridge Gas Distribution Sales Service Customer

Line No.	Particulars	Union - Approved EB-2017-0087				
		Rate M1 Residential ($) (1)	Rate M1 Commercial ($) (2)	Rate M2 Small ($) (3)	Rate M2 Large ($) (4)	Rate M4 Small ($) (5)
		(a)	(b)	(c)	(d)	(e)
1	Delivery Charges	448	2,166	6,208	22,650	78,450
2	Gas Supply Charges	300	3,134	8,175	34,063	119,220
3	Total Bill (6)	747	5,300	14,383	56,713	197,670
		Enbridge Gas Distribution - Approved EB-2017-0347				
		Rate 1 Residential ($) (1)	Rate 6 Commercial ($) (2)	Rate 6 Small ($) (3)	Rate 6 Large ($) (4)	Rate 110 Small ($) (5)
		(a)	(b)	(c)	(d)	(e)
4	Delivery Charges	504	3,174	6,323	20,726	56,799
5	Gas Supply Charges	379	3,937	10,271	42,797	138,452
6	Total Bill (6)	883	7,111	16,595	63,523	195,251

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management (“LPMA”)

Rate Setting Issues List – Issue No.13

Reference: Exhibit B, Tab 1, page 31

Question:

a) With respect to the Normalized Average Consumption (“NAC”) Study, the evidence indicates that changes to NAC would be considered as part of a future rate proceeding. Does this mean that Amalco may bring forward a proposal as part of the annual adjustment process noted on page 26 sometime in the deferred rebasing period?

b) Please explain why Amalco intends to bring forward a proposal to address the cost allocation of the Panhandle System and St. Clair System in its 2019 rates application when the Board has already determined that consideration of any changes to the cost allocation methodology are to be deferred until Union’s next cost of service or custom IR application.

Response:

a) Please see the response to BOMA Interrogatory#33 found at Exhibit C.BOMA.33.

b) Union does not agree that the Board decided in Union’s 2018 Rates proceeding (EB-2017-0087) that any changes in the cost allocation of the Panhandle and St. Clair Systems must be deferred until Union’s next rebasing proceeding or that Union could not bring forward changes in cost allocation in its 2019 rates application. Union did not file any evidence in EB-2017-0087 on its proposal to change the allocation of costs related to the Panhandle System or the impacts on customers of not changing allocation methodologies.

   The Applicants intend to address the cost allocation of the Panhandle System and St. Clair System in its 2019 Rates application because the addition of the Panhandle Reinforcement project to the 2013 Board-approved cost allocation methodology caused significant impacts to certain rate classes that did not reflect the principle of cost causality and to respond to concerns raised by customers. With Amalco’s proposed deferred rebasing, Union believes that it would be appropriate to address the allocation of the Panhandle System and St. Clair System costs in its 2019 Rates application as opposed to its next rebasing in 2029.

   Union believes the cost allocation of the Panhandle System and St. Clair System can be addressed as a standalone proposal without requiring a full update to the cost allocation study as the Panhandle Reinforcement Project costs are within a single cost study function. Union intends to use the 2013 Board-approved cost allocation study, updated for the Panhandle Reinforcement Project as the basis of a cost allocation proposal. Union's proposal will include splitting the existing Ojibway/St. Clair Demand classification into separate Panhandle System Demand and St. Clair System Demand classifications and propose a new allocation methodology for each classification. Further details of Union's cost allocation proposal will be included as part of its 2019 Rates application.

Please also see the response to CCC Interrogatory#31found at Exhibit C.CCC.31.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.14

Reference: Exhibit B, Tab 1, Attachment 2

Question:
Did Union and/or EGD consult with ratepayers or ratepayer representatives on the proposed targets for each of the items under Customer Focus in the proposed scorecard. If not, why not?

Response

No. The Applicants built the Customer Focus section of the proposed scorecard using the Board's SQRs from the OEB's Reporting and Record Keeping Requirements.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.15

Reference: Exhibit B, Tab 1, page 28

Question:
a) Are there any differences in the proposed annual reporting proposed by the applicants as compared to the current annual reporting provided by Union under its current incentive mechanism?
b) If the answer to (a) is yes, please explain the differences and provide the reasons for the changes.
c) Would the annual reporting be part of the annual adjustment process noted on page 26, part of the application for the disposition of actual year-end deferral account balances, or a stand alone reporting?
d) Will the Board and intervenors have the opportunity to provide the applicants questions on the annual reporting? If not, please explain why not.

Response

a) Yes.

b) The Scorecard was added in place of Service Quality Indicators. Continuity schedules related to unregulated property, plant and equipment were removed as the Applicants deemed this reporting was not applicable to the annual reporting process.

c) The annual reporting would be provided as part of the non-commodity deferral account proceeding.

d) Yes.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
London Property Management ("LPMA")

Rate Setting Issues List – Issue No.16

Reference: Exhibit B, Tab 1, page 27

Question:
Given the extensive and rapidly changing business environment that the applicants purport to be subject too over the deferred rebasing period, please explain why annual stakeholder meetings would not be more appropriate, and timely than the proposal to hold stakeholder meetings every other year.

Response

Please see the response to OAPPA Interrogatory #8 found at Exhibit C.OAPPA.8.