500 Consumers Road
North York, Ontario M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

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

February 21, 2014

VIA RESS, EMAIL and COURIER

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

Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
Undertaking Responses

Enclosed please find Undertaking Responses in Enbridge Gas Distribution's proceeding as follows:

Exhibits J1.1; J1.3; J1.4; J1.8; J1.9; and J1.10

This submission was filed through the Board's RESS and is available on the Company's website at www.enbridgegas.com/ratecase.

Yours truly,

(original signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

UNDERTAKING J1.1

UNDERTAKING

TR 1

To provide Enbridge Gas Distribution’s 2013 Corporate Financial Results.

RESPONSE

Please see Attachment 1 - 2013 Annual Financial Statements and Attachment 2 - 2013 Annual MD&A.

Witness: K. Culbert

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2013

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. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

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

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

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

(Signed)

Glenn W. Beaumont
President

(Signed)

William M. Ramos
Vice President, Finance & Regulatory

February 13, 2014

February 13, 2014

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, 2013 and December 31, 2012 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for each of the three years in the period ended December 31, 2013, 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, www.pwc.com/ca

pwc

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2013 and December 31, 2012 and its results of operations and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Professional Accountants, Licensed Public Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Gas commodity and distribution revenue *(Note 21)*	**2,221**	1,869	1,880
Transportation of gas for customers	**328**	345	421
	2,549	2,214	2,301
Gas commodity and distribution costs, excluding depreciation *(Note 21)*	**(1,480)**	(1,229)	(1,296)
Gas distribution margin	**1,069**	985	1,005
Other revenue *(Note 5)*	**99**	202	103
	1,168	1,187	1,108
Expenses			
Operating and administrative *(Note 21)*	**454**	449	437
Depreciation and amortization *(Note 3)*	**304**	320	302
Municipal and other taxes	**42**	40	41
Earnings sharing *(Note 5)*	**-**	10	13
	800	819	793
	368	368	315
Affiliate financing income *(Note 21)*	**63**	63	63
Interest expense *(Notes 12 and 21)*	**(171)**	(170)	(172)
	260	261	206
Income taxes *(Note 18)*			
Current	**(52)**	(33)	(44)
Deferred	**9**	(20)	9
	(43)	(53)	(35)
Earnings from continuing operations	**217**	208	171
Discontinued operations *(Note 6)*			
Earnings from discontinued operations before income taxes	**-**	6	2
Income taxes from discontinued operations	**-**	(2)	-
Earnings from discontinued operations	**-**	4	2
Earnings	**217**	212	173
Preference share dividends *(Note 14)*	**(2)**	(2)	(2)
Earnings attributable to the common shareholder	**215**	210	171

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings	**217**	212	173
Other comprehensive income/(loss), net of tax *(Note 16)*			
Change in unrealized gain/loss on cash flow hedges	**81**	(1)	(1)
Reclassification to earnings of realized loss on cash flow hedges	**1**	2	2
Reclassification to earnings of unrealized gain on cash flow hedges	**(2)**	-	-
Actuarial gain/(loss) on other postretirement benefits *(Note 19)*	**10**	(3)	(10)
Change in foreign currency translation adjustment	**1**	-	-
Other comprehensive income/(loss)	**91**	(2)	(9)
Comprehensive income	**308**	210	164
Preference share dividends	**(2)**	(2)	(2)
Comprehensive income attributable to the common shareholder	**306**	208	162

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

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Preference shares *(Note 14)*	**100**	100	100
Common shares *(Note 14)*			
Balance at beginning of year	**1,137**	1,137	1,071
Common shares issued	**150**	-	66
Balance at end of year	**1,287**	1,137	1,137
Additional paid-in capital			
Balance at beginning of year	**1,148**	1,131	1,131
Disposition *(Note 6)*	**-**	17	-
Balance at end of year	**1,148**	1,148	1,131
Retained earnings/(deficit)			
Balance at beginning of year	**7**	(2)	47
Earnings attributable to the common shareholder	**215**	210	171
Common share dividends declared	**(200)**	(201)	(220)
Balance at end of year	**22**	7	(2)
Accumulated other comprehensive income/(loss) *(Note 16)*			
Balance at beginning of year	**(26)**	(24)	(15)
Other comprehensive income/(loss)	**91**	(2)	(9)
Balance at end of year	**65**	(26)	(24)
Total shareholders' equity	**2,622**	2,366	2,342

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Operating activities			
Earnings	**217**	212	173
Earnings from discontinued operations	**-**	(4)	(2)
Depreciation and amortization	**304**	320	302
Deferred income taxes	**(9)**	20	(9)
Recognition of regulatory asset *(Note 5)*	**-**	(89)	-
Other	**12**	13	9
Premium on issuance of term notes	**12**	-	-
Changes in operating assets and liabilities *(Note 20)*	**(86)**	71	15
Cash provided by continuing operations	**450**	543	488
Cash provided by discontinued operations *(Note 6)*	**-**	12	3
	450	555	491
Investing activities			
Additions to property, plant and equipment	**(519)**	(414)	(414)
Additions to intangible assets	**(34)**	(38)	(34)
Change in construction payable	**6**	(11)	5
Proceeds on sale of assets *(Note 6)*	**-**	72	-
	(547)	(391)	(443)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**(210)**	33	212
Net change in short-term note payable to affiliate company *(Note 21)*	**2**	5	2
Debenture and term note issues	**400**	-	100
Debenture and term note repayments	**-**	-	(150)
Common shares issued *(Note 14)*	**150**	-	-
Preference share dividends	**(2)**	(2)	(2)
Common share dividends	**(200)**	(206)	(218)
Other	**(2)**	-	4
	138	(170)	(52)
Increase/(decrease) in cash and cash equivalents	**41**	(6)	(4)
Cash and cash equivalents at beginning of year	**3**	9	13
Cash and cash equivalents at end of year	**44**	3	9
Cash and cash equivalents – discontinued operations *(Note 6)*	**-**	-	(3)
Cash and cash equivalents – continuing operations	**44**	3	6
Supplementary cash flow information			
Income taxes paid	**42**	31	62
Interest paid *(Note 12)*	**169**	176	169

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2013**	2012
(millions of Canadian dollars, number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**44**	3
Accounts receivable and other *(Notes 7, 18 and 21)*	**706**	605
Gas inventories *(Note 2)*	**382**	341
	1,132	949
Property, plant and equipment, net *(Note 8)*	**5,869**	5,532
Investment in affiliate company *(Note 21)*	**825**	825
Deferred amounts and other assets *(Note 9)*	**379**	432
Intangible assets, net *(Note 10)*	**174**	177
	8,379	7,915
Liabilities and shareholders' equity		
Current liabilities		
Bank indebtedness	**4**	5
Short-term borrowings *(Note 12)*	**389**	596
Accounts payable and other *(Notes 11 and 21)*	**769**	730
Current maturities of long-term debt *(Note 12)*	**400**	-
	1,562	1,331
Long-term debt *(Note 12)*	**2,399**	2,387
Other long-term liabilities *(Note 13)*	**1,026**	1,094
Deferred income taxes *(Note 18)*	**395**	362
Loans from affiliate company *(Notes 12 and 21)*	**375**	375
	5,757	5,549
Commitments and contingencies *(Notes 21 and 22)*		
Shareholders' equity		
Share capital *(Note 14)*		
Preference shares *(convertible; 4 outstanding at December 31, 2013 and 2012)*	**100**	100
Common shares *(151 and 142 outstanding at December 31, 2013 and 2012, respectively)*	**1,287**	1,137
Additional paid-in capital	**1,148**	1,148
Retained earnings	**22**	7
Accumulated other comprehensive income/(loss) *(Note 16)*	**65**	(26)
	2,622	2,366
	8,379	7,915

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

Approved by the Board of Directors:

(Signed)

Glenn W. Beaumont
President

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

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

The Company also owns and operates regulated and unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 8)*; amortization rates and carrying value of intangible assets *(Note 10)*; valuation of stock- based compensation *(Note 15)*; fair value of financial instruments *(Note 17)*; provisions for income taxes *(Note 18)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 19),* commitments and contingencies *(Note 22)*; and fair value of asset retirement obligations (ARO). Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its subsidiaries. All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION

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

The Regulators exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities *(Note 5)*.

REVENUE RECOGNITION

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

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

PUSH-DOWN ACCOUNTING

The Company has elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge. On the original acquisition, the fair value adjustment was recorded by Enbridge rather than by the Company. Upon adopting push-down accounting, the historical cost of the Company's property, plant and equipment and related accounts was adjusted by the remaining unamortized fair value adjustment.

DERIVATIVE INSTRUMENTS AND HEDGING

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges at December 31, 2013 or 2012.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/loss (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

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

Classification of Derivatives

The Company recognizes the fair value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

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

Balance Sheet Offset

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

Transaction Costs

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

INCOME TAXES

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

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

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the date of the Consolidated Statement of Financial Position. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

The functional currency of the Company’s only foreign operation, St. Lawrence, is the United States dollar. The effects of translating the financial statements of St. Lawrence to Canadian dollars are included in the cumulative translation adjustment component of Accumulated other comprehensive income/loss (AOCI). Asset and liability accounts are translated at the exchange rates in effect on the date of the Consolidated Statement of Financial Position, while revenues and expenses are translated at monthly average rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

The Company extinguishes liabilities when a creditor has relieved the Company of its obligation, which occurs when the Company’s financial institution honours a cheque that the creditor has presented for payment. Accordingly, obligations for which the Company has issued cheque payments that have not been presented to the financial institution are included in Accounts payable and other on the Consolidated Statements of Financial Position.

GAS INVENTORIES

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

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

At December 31, 2013, $28 million (2012 - $51 million) of natural gas was held on behalf of transportation service customers. These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates authorized by the Regulators. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have a future benefit.

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

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs which the Regulators have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; derivative financial instruments; and deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Company's Customer Information System (CIS) and software costs. The Company capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS

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

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2013, new mortality assumptions were adopted by the Company for the measurement of the December 31, 2013 benefit obligations, moving from the tables previously issued by the Canadian Institute of Actuaries (CIA) to the proposed revised tables. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. During the year ended December 31, 2012, the Company refined the methodology by which it determines discount rates, in particular, refining the method by which it estimates spreads for bonds with longer term maturities. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- Interest cost of pension plan obligations;
- Expected return on pension fund assets; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

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

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

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

The Company expects to recover pension expense in future rates and therefore records a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012, a regulatory asset related to OPEB obligation was not recorded as a rate order allowing for the recovery of these costs in rates had not yet been obtained. Commencing in 2012, pursuant to a specific rate order allowing for recovery in rates of OPEB costs determined on an accrual basis in rates, a corresponding regulatory asset was recognized. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION

Enbridge grants stock-based compensation to certain employees and senior officers of the Company through four long-term incentive compensation plans. Compensation expense associated with each of the plans, as determined under the methods outlined below is recognized in Operating and administrative expense. Amounts owing to Enbridge in respect of stock-based compensation are payable on a quarterly basis.

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISOs granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility.

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

Performance Stock Units (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company's shares . The value of the PSUs is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS AND CONTINGENCIES
Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

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

3. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

ADOPTION OF NEW STANDARDS
Balance Sheet Offsetting
Effective January 1, 2013, the Company adopted Accounting Standards Update (ASU) 2011-11 and ASU 2013-01, which require enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. As the adoption of these updates impacted disclosure only, there was no impact to the Company's consolidated financial position for the current or prior periods presented.

Accumulated Other Comprehensive Income
Effective January 1, 2013, the Company adopted ASU 2013-02, which requires enhanced disclosures on amounts reclassified out of AOCI. As the adoption of this update impacted disclosure only, there was no impact to the Company's consolidated financial statements for the current or prior periods presented.

Presentation of Unrecognized Tax Benefits
Effective December 31, 2013, the Company elected to early adopt ASU 2013-11 which requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES
Obligations Resulting from Joint and Several Liability Arrangements
ASU 2013-04 was issued in February 2013 and provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively.

Parent's Accounting for the Cumulative Translation Adjustment
ASU 2013-05 was issued in March 2013 and provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied prospectively.

CHANGES IN ACCOUNTING ESTIMATES

Depreciation Rates

In 2013, the Company revised depreciation rates based on the results of a new depreciation study which was approved by the OEB as part of the cost of service settlement applicable to 2013. Had rates remained the same, depreciation and amortization expense would have been higher by $32 million for the year ended December 31, 2013.

4. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In connection with the preparation of the Company's consolidated financial statements for the nine months ended September 30, 2013, an error was identified in the manner in which a component of gas commodity and distribution costs had been recorded. The matter related to the accounting true-up mechanism between actual gas commodity and distribution costs incurred and the regulator-approved price charged to customers.

In accordance with accounting guidance found in Accounting Standards Codification (ASC) 250-10 (Securities and Exchange Commission (SEC) Staff Accounting Bulletin No. 99, *Materiality*), the Company assessed the materiality of the error and concluded that it was not material to any of the Company's previously issued consolidated financial statements. In accordance with guidance found in ASC 250-10 (SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*), the Company revised its comparative consolidated financial statements to correct the effect of this matter. As a result of this error, the Company remitted excess income taxes totaling $22 million to the Canada Revenue Agency (CRA) in relation to the 2010, 2011 and 2012 taxation years and over shared earnings with ratepayers under an earnings sharing mechanism in relation to 2010, 2011 and 2012. The Company expects that it will recover the tax overpayment from the CRA.

The following tables present the effect of this correction on individual line items within the Company's Consolidated Statements of Earnings and Consolidated Statements of Financial Position. The effects which flow through to the individual line items of Earnings, Gas commodity and distribution costs excluding depreciation, Income taxes, Gas inventories, Accounts receivable and other, Accounts payable and other, and Changes in operating assets and liabilities of the Consolidated Statements of Cash Flows are not significant and have no net effect on the Company's cash flows from operating activities. Comparative figures as at December 31, 2012 and for the years ended December 31, 2012 and 2011 have been revised throughout these financial statements as necessary to reflect these revisions.

	Year ended December 31, 2012			Year ended December 31, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)						
Gas commodity and distribution costs excluding depreciation	(1,199)	(30)	(1,229)	(1,268)	(28)	(1,296)
Income tax expense - current	(41)	8	(33)	(52)	8	(44)
Earnings from continuing operations	230	(22)	208	191	(20)	171
Earnings	234	(22)	212	193	(20)	173
Earnings attributable to the common shareholder	232	(22)	210	191	(20)	171

	December 31, 2012		
	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)			
Accounts receivable and other	594	11	605
Gas inventories	326	15	341
Accounts payable and other	648	82	730
Retained earnings	63	(56)	7

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

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

RATE APPROVAL

For the year ended December 31, 2013, Enbridge Gas Distribution’s rates were set pursuant to an OEB approved settlement agreement and decision related to its 2013 cost of service rate application. For the years ended December 31, 2013, 2012 and 2011, St. Lawrence’s 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, municipal and other taxes, interest and income taxes. Rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of Enbridge Gas Distribution and St. Lawrence to demonstrate to the Regulators the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken.

For the years ended December 31, 2012 and 2011, Enbridge Gas Distribution’s annual rates were set using a revenue per customer cap Incentive Regulation (IR) methodology which adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions. Under the IR mechanism, Enbridge Gas Distribution was allowed to earn and fully retain 100 basis points (bps) over the base return. Any return over 100 bps was required to be shared with customers on an equal basis.

In July 2013, Enbridge Gas Distribution filed an application with the OEB for the setting of rates through a customized IR mechanism for the period of 2014 through 2018. A decision is anticipated in the second quarter of 2014.

The cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution

Enbridge Gas Distribution’s rates for 2013 included an after-tax rate of return on common equity of 8.93% (2012 and 2011 - 8.39%) based on a 36% (2012 and 2011 - 36%) deemed common equity component of rate base. The earnings sharing mechanism, which was previously in effect under the IR methodology, did not apply in 2013.

St. Lawrence

St. Lawrence’s approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2013 (2012 - 10.5%) based on a 50% (2012 - 50%) deemed common equity component of rate base. Any earnings above a return on equity of 11% (2012 - 11%) were shared equally with customers. The calculation of such earnings was cumulative from January 1, 2010 to December 31, 2013 and resulted in no sharing impact as at December 31, 2013 (2012 - nil).

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement
The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. The Regulators' future actions may differ from current expectations or future legislative changes may impact the regulatory environment in which the Company operates. To the extent that the Regulators' future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

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

December 31,	**2013**	2012	Consolidated Statement of Financial Position Location**	Estimated Recovery/ Settlement Period *(years)*
(millions of Canadian dollars)				
Regulatory assets/(liabilities)				
Enbridge Gas Distribution				
Deferred income taxes[1]	**209**	198	DA	*
OPEB[2]	**89**	89	AR/DA	19
Shared savings mechanism[3]	**16**	-	AR	*
Average use true-up variance[4]	**10**	4	AR	*
Unaccounted for gas variance[5]	**8**	2	AR	1
Customer care CIS rate smoothing deferral[6]	**5**	-	DA	5
Deferred rate hearing costs[7]	**4**	5	AP/DA	2
Post-retirement true-up variance[8]	**3**	-	AR	1
Pension plans, net[9]	**2**	115	DA/OLTL	*
Future removal and site restoration reserves[10]	**(905)**	(859)	OLTL	*
Transactional services deferral[11]	**(51)**	(26)	AP	1
Earnings sharing deferral[12]	**(7)**	(10)	AP	*
Purchased gas variance[13]	**(6)**	(82)	AP	1
Storage and transportation deferral[14]	**(3)**	(1)	AP	1
Other regulatory assets and liabilities	**1**	4	***	***
	(625)	(561)		
St. Lawrence				
Other regulatory assets and liabilities	**(1)**	8	***	***
	(1)	8		
	(626)	(553)		

* Refer to the footnote for details
** AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities
*** Dependent on the nature of the item

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

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

3 *Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

4 *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual weather normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

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

6 *Customer care CIS rate smoothing deferral represents the difference between the forecast costs and the approved costs for customer care and CIS reflected in rates. The balance will accumulate during 2013 to 2015 when the cost per customer exceeds the cost approved for recovery in rates. The balance will be drawn down during 2016 to 2018 when the cost per customer is lower than the cost approved for recovery in rates. Enbridge Gas Distribution has received OEB approval to collect from or refund to customers any remaining balance after 2018. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

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

8 *Post-retirement true-up variance is the difference between the actual cost and the approved cost of pension and OPEB reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the subsequent year, up to a maximum of $5 million per year. Any amounts in excess of $5 million per year will be deferred for refund or collection in the next subsequent year. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

9 *The pension plan balance represents the regulatory offset to the pension liability/asset to the extent the amounts are to be collected/refunded in future rates. The settlement period for this balance is not determinable. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would have been charged to earnings and OCI based on the accrual basis of accounting.*

10 *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

11 *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

12 *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement applicable to 2012. The earnings sharing is payable to customers and represented 50% of normalized 2012 Canadian GAAP earnings represented by the ROE in excess of 100 basis points above the allowed utility return on equity threshold applicable to Enbridge Gas Distribution under IR. The December 31, 2012 balance related to the year ended December 31, 2012. Earnings sharing did not apply to the 2013 COS Settlement. There would be no change in the treatment of this item in the absence of rate regulation.*

13 *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established. Purchased gas variance for 2012 has been revised as per Note 4.*

14 *Storage and transportation deferral represents the difference between the actual cost and the approved cost of natural gas storage and transportation reflected in rates. Enbridge Gas Distribution has historically been granted OEB approval to collect this balance from or to refund this balance to customers, generally in the subsequent year. In the absence of rate regulation, the actual cost of natural gas storage and transportation would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount, as the right to collect or refund the revenue or costs has been established.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

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

In 2012, the Company received a rate order from the OEB permitting recovery of OPEB costs in the amount of $89 million. The rate order allows this amount to be collected in rates over a 20-year period commencing in 2013, and was presented in Other revenue for the year ended December 31, 2012. In the absence of rate regulation, this earnings impact would not have been recorded.

Operating Cost Capitalization

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

The Company entered into a services contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2013, cumulative costs relating to this services contract of $154 million (2012 - $144 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

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

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2013, the net book value of these costs was $73 million (2012 - $86 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories

Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. Included in gas inventories at December 31, 2013 is $40 million (2012 - $39 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred and inventory would be recorded at the lower of cost or market value.

Depreciation

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

6. DISCONTINUED OPERATIONS

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund (the Fund), an affiliated entity under common control, for proceeds of $72 million. Project Amherstburg consisted primarily of property, plant and equipment and intangible assets. The excess of the sale price over the net book value at the time of disposition of $17 million inclusive of deferred income tax recoveries of $10 million were recognized as Additional paid-in capital. No gain or loss was recognized in earnings on the disposition; however $5 million of cash income taxes incurred on the related capital gain remains as a charge to consolidated earnings for the year ended December 31, 2012.

In 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. The total consideration transferred for Project Amherstburg was approximately $66 million, which was primarily funded by the issuance of common shares (1,612,367 shares).

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2013**	2012
(millions of Canadian dollars)		
Trade receivables	**357**	321
Unbilled revenues	**211**	170
Regulatory assets *(Note 5)*	**54**	21
Short-term portion of derivative assets *(Note 17)*	**36**	-
Agent billing and collection receivable	**15**	44
Due from affiliates *(Note 21)*	**13**	12
Taxes receivable	**9**	40
Prepaid expenses	**7**	4
Current deferred income taxes *(Note 18)*	**2**	5
Other	**33**	29
Allowance for doubtful accounts	**(31)**	(41)
	706	605

8. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2013**	2012
(millions of Canadian dollars)			
Regulated property, plant and equipment			
Gas mains	**3.1%**	**3,342**	3,132
Gas services	**3.0%**	**2,667**	2,530
Regulating and metering equipment	**6.0%**	**781**	757
Gas storage	**2.4%**	**314**	295
Land and right-of-way	**1.1%**	**71**	70
Computer technology	**37.2%**	**36**	42
Under construction	**-**	**198**	102
Construction materials inventory	**-**	**35**	38
Other	**7.5%**	**280**	274
		7,724	7,240
Accumulated depreciation		**(1,949)**	(1,798)
		5,775	5,442
Unregulated property, plant and equipment			
Gas storage	**2.2%**	**87**	86
Other	**1.6%**	**24**	18
		111	104
Accumulated depreciation		**(17)**	(14)
		94	90
Property, plant and equipment, net		**5,869**	5,532

Depreciation expense, including amounts collected for future removal and site restoration costs, was $267 million for the year ended December 31, 2013 (2012 - $289 million, 2011 - $271 million).

9. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2013**	2012
(millions of Canadian dollars)		
Regulatory assets *(Note 5)*	**312**	414
Long-term portion of derivative assets *(Note 17)*	**46**	1
Deferred financing costs	**11**	11
Pension and OPEB asset *(Note 19)*	**8**	3
Other	**2**	3
	379	432

At December 31, 2013, deferred amounts of $31 million (2012 - $29 million) were subject to amortization and are presented net of accumulated amortization of $20 million (2012 - $18 million). Amortization expense for the year ended December 31, 2013 was $2 million (2012 - $2 million, 2011 - $2 million).

10. INTANGIBLE ASSETS

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	**22.8%**	**162**	**(61)**	**101**
CIS	**10%**	**127**	**(54)**	**73**
		289	**(115)**	**174**

December 31, 2012	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	20.6%	128	(37)	91
CIS	10.0%	127	(41)	86
		255	(78)	177

Intangible assets include $19 million of work-in-progress as at December 31, 2013 (2012 - $33 million). Total amortization expense for intangible assets was $37 million for the year ended December 31, 2013 (2012 - $31 million, 2011 - $31 million). The Company expects aggregate amortization expense for the years ending December 31, 2014 through 2018 of $41 million, $43 million, $49 million, $47 million and $45 million, respectively.

11. ACCOUNTS PAYABLE AND OTHER

December 31,	**2013**	2012
(millions of Canadian dollars)		
Operating accrued liabilities	**329**	279
Budget billing plan payable	**82**	59
Regulatory liabilities *(Note 5)*	**76**	121
Security deposits	**62**	67
Dividends payable	**51**	51
Due to affiliates *(Note 21)*	**49**	10
Trade payables	**46**	59
Interest payable	**28**	26
Taxes payable	**22**	28
Current portion of OPEB liability *(Note 19)*	**4**	5
Other	**20**	25
	769	730

12. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2013**	2012
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	85
Medium term notes	5.33%	2014-2050	**2,695**	2,295
Commercial paper and credit facility draws, net			**382**	590
Other[1]			**26**	13
Total debt			**3,188**	2,983
Current maturities			**(400)**	-
Short-term borrowings	1.13%		**(389)**	(596)
Long-term debt			**2,399**	2,387
Loans from affiliate company *(Note 21)*			**375**	375

1 *Consists of note payable to affiliate company and debt premium*

For the years ending December 31, 2014 through 2018, medium-term note maturities are $400 million, $1 million, $2 million, $201 million and $2 million, respectively. The Company's debentures and medium term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2014 through 2018 are $146 million, $130 million, $130 million, $130 million and $120 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Debentures and medium-term notes	**138**	139	140
Loans from affiliate company *(Note 21)*	**27**	27	27
Commercial paper and credit facility draws	**4**	2	3
Other interest and finance costs	**9**	8	8
Capitalized	**(7)**	(6)	(6)
	171	170	172

In 2013, total interest paid to third parties was $142 million (2012 - $142 million, 2011 - $149 million) and total interest paid to affiliate company was $27 million (2012 - $34 million, 2011 - $20 million).

CREDIT FACILITIES

The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The 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 August 2013, the Company extended the term out date of its $700 million committed line of credit for an additional year to August 2014, with a maturity date in August 2015.

December 31, 2013	Maturity Dates	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.	2015	**700**	**370**	**330**
St. Lawrence Gas Company, Inc.	2019	**13**	**12**	**1**
Total credit facilities		**713**	**382**	**331**

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

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

The Company's borrowings, whether debentures or medium-term notes, are unsecured. When issuing any new indebtedness with a maturity over 18 months, covenants contained in the Company's trust indenture require the pro forma long-term debt interest coverage ratio be at least 2.0 times for 12 consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as U.S. GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of financing costs and intercompany interest expense less gains on asset dispositions divided by the annual interest requirement. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2013, the Company was in compliance with this covenant.

13. OTHER LONG-TERM LIABILITIES

December 31,	**2013**	2012
(millions of Canadian dollars)		
Regulatory liabilities *(Note 5)*	**916**	867
Pension and OPEB liabilities *(Note 19)*	**104**	226
Other	**6**	1
	1,026	1,094

14. 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

	2013		2012		2011	
December 31,	Number of shares	Amount	Number of shares	Amount	Number of shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**142.3**	**1,137**	142.3	1,137	140.7	1,071
Common shares issued	**8.3**	**150**	-	-	1.6	66
Balance at end of year	**150.6**	**1,287**	142.3	1,137	142.3	1,137

PREFERENCE SHARES

December 31, 2013, 2012, and 2011	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preference shares in millions)			
Group 1	0.2	-	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 2, Series D, Cumulative Redeemable Convertible	4	-	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	-	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	-	-
Group 5	10	-	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2013, no preference shares have been redeemed.

On July 1, 2014, 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, 2014 and every five years thereafter.

15. STOCK OPTION AND STOCK UNIT PLANS

Enbridge's four long-term incentive compensation plans include the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. The Company reimburses Enbridge for stock-based compensation costs associated with its employees on a quarterly basis.

INCENTIVE STOCK OPTIONS

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

December 31, 2013	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**2,527**	**24.88**		
Options granted	**456**	**44.81**		
Options exercised[1]	**(264)**	**16.93**		
Options cancelled	**(229)**	**30.97**		
Options outstanding at end of year	**2,490**	**28.81**	**6.2**	**40**
Options vested at end of year[2]	**1,430**	**22.12**	**4.7**	**33**

1 The total intrinsic value of ISOs exercised during the year ended December 31, 2013 was $7 million (2012 - $11 million; 2011 - $8 million) and cash received by Enbridge on exercise was $2 million (2012 - $6 million; 2011 - $7 million).
2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2013 was $2 million (2012 - $2 million; 2011 - $1 million).

Weighted average assumptions used to determine the fair value of the ISOs using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2013**	2012	2011
Fair value per option *(Canadian dollars)*[1]	**5.27**	4.81	4.19
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	6
Expected volatility[3]	**17.4%**	19.7%	18.6 %
Expected dividend yield[4]	**2.8%**	3.0%	3.4%
Risk-free interest rate[5]	**1.2%**	1.3%	2.9%

1 Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $5.15 (2012 - $4.65; 2011 - $4.01) for Canadian employees and US$5.63 (2012 - US$5.58, 2011 - US$5.11) for United States employees.
2 The expected option term is based on historical exercise practice.
3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.
4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.
5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2013 for ISOs was $3 million (2012 - $3 million, 2011 - $3 million). At December 31, 2013, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $3 million. The cost is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted by Enbridge to executive officers of the Company and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on August 15, 2012 under the 2007 plan. Time vesting requirements for the 2012 grant will be fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on Enbridge's share price and must be met by February 15, 2019 or the options expire. If targets are met by February 15, 2019, the options are exercisable until August 15, 2020.

December 31, 2013	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(options in thousands; exercise price and intrinsic value in Canadian dollars)				
Options outstanding at beginning of year	**169**	**39.34**		
Options cancelled	**(169)**	**39.34**		
Options outstanding at end of year	**-**	**-**	**-**	**-**

Weighted average assumptions used to determine the fair value of the PBSOs using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	**2013**
Fair value per option *(Canadian dollars)*	**4.25**
Valuation assumptions	
Expected option term *(years)*[1]	**8**
Expected volatility[2]	**16.1%**
Expected dividend yield[3]	**2.8%**
Risk-free interest rate[4]	**1.6%**

1 *The expected option term is based on historical exercise practice.*
2 *Expected volatility is determined with reference to historic daily share price volatility.*
3 *The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.*
4 *The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.*

Compensation expense for PBSOs was nil for the years ended December 31, 2013, 2012, and 2011. At December 31, 2013, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $1 million. The cost is expected to be fully recognized over a weighted average period of approximately four years.

PERFORMANCE STOCK UNITS

Enbridge has a PSU Plan for senior officers of the Company where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two if Enbridge performs within the highest range of its performance targets. The 2011, 2012 and 2013 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's earnings per share, adjusted for unusual non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2013 expense, multipliers of two, based upon multiplier estimates at December 31, 2013, were used for each of the 2011, 2012 and 2013 PSU grants.

December 31, 2013	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**36**		
Units granted	**10**		
Units cancelled	**(7)**		
Units matured[1]	**(21)**		
Dividend reinvestment	**1**		
Units outstanding at end of year	**19**	**1.5**	**2**

1 *The total amount paid by Enbridge during the year ended December 31, 2013 for PSUs was $2 million (2012 - $1 million; 2011 - $1 million).*

Compensation expense recorded for the year ended December 31, 2013 for PSUs was $4 million (2012 - $7 million; 2011 - $6 million). As of December 31, 2013, 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.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge’s weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2013	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value *(millions)*
(units in thousands; intrinsic value in Canadian dollars)			
Units outstanding at beginning of year	**228**		
Units granted	**94**		
Units cancelled	**(1)**		
Units matured[1]	**(127)**		
Dividend reinvestment	**9**		
Units outstanding at end of year	**203**	**1.4**	**9**

1 *The total amount paid by Enbridge during the year ended December 31, 2013 for RSUs was $5 million (2012 - $5 million; 2011 - $5 million).*

Compensation expense recorded for the year ended December 31, 2013 for RSUs was $5 million (2012 - $5 million; 2011 - $5 million). As of December 31, 2013, 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.

16. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI for the years ended December 31, 2013, 2012 and 2011, are as follows:

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2013	**(10)**	**(6)**	**(10)**	**(26)**
Other comprehensive income retained in AOCI	**109**	**1**	**14**	**124**
Other comprehensive income reclassified to earnings				
Interest rate contracts[1]	**(1)**	**-**	**-**	**(1)**
	108	**1**	**14**	**123**
Tax impact				
Income tax on amounts retained in AOCI	**(28)**	**-**	**(4)**	**(32)**
	(28)	**-**	**(4)**	**(32)**
Balance at December 31, 2013	**70**	**(5)**	**-**	**65**

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2012	(11)	(6)	(7)	(24)
Other comprehensive loss retained in AOCI	(1)	-	(4)	(5)
Other comprehensive loss reclassified to earnings				
Interest rate contracts[1]	2	-	-	2
	1	-	(4)	(3)
Tax impact				
Income tax on amounts retained in AOCI	-	-	1	1
	-	-	1	1
Balance at December 31, 2012	(10)	(6)	(10)	(26)

	Cash Flow Hedges	Cumulative Translation Adjustment	Unamortized OPEB Actuarial Loss	Total
(millions of Canadian dollars)				
Balance at January 1, 2011	(12)	(6)	3	(15)
Other comprehensive income retained in AOCI	(2)	-	(13)	(15)
Other comprehensive loss reclassified to earnings				
Interest rate contracts[1]	3	-	-	3
	1	-	(13)	(12)
Tax impact				
Income tax on amounts retained in AOCI	1	-	3	4
Income tax on amounts reclassified to earnings	(1)	-	-	(1)
	-	-	3	3
Balance at December 31, 2011	(11)	(6)	(7)	(24)

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

17. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET PRICE RISK

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

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

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations in the exchange rate of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2012 - nil).

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense related to variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances. The Company uses qualifying derivative instruments to manage interest rate risk.

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil (2012 - nil).

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at December 31, 2013 or 2012.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with these counterparties in those particular circumstances. The following table also summarizes the maximum potential settlement amount in the event of those specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2013	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable and other					
Interest rate contracts	**36**	**-**	**36**	**-**	**36**
Deferred amounts and other assets					
Interest rate contracts	**46**	**-**	**46**	**-**	**46**
Total net derivative asset					
Interest rate contracts	**82**	**-**	**82**	**-**	**82**

December 31, 2012	Derivative Instruments Used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	1	-	1	-	1
Accounts payable and other					
Interest rate contracts	(1)	-	(1)	-	(1)
Other long-term liabilities					
Interest rate contracts	(1)	-	(1)	-	(1)
Total net derivative liability					
Interest rate contracts	(1)	-	(1)	-	(1)

The Company's derivatives instruments mature through 2017 and have a notional principal of $535 million for interest rate contracts for short-term borrowings (2012 - $673 million), and $747 million for interest rate contracts on long-term debt (2012 - $1,007 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,	**2013**	2012	2011
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Interest rate contracts	**109**	(1)	(2)
	109	(1)	(2)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(2)**	(2)	(3)
	(2)	(2)	(3)
Amount of gains reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**2**	-	-
	2	-	-

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

The Company estimates that $2 million in AOCI related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 37 months at December 31, 2013.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 21 and 22)* as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 12)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2013. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 20 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

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

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate.

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

Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

The Company had group credit concentration and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

	December 31, 2013	December 31, 2012
(millions of Canadian dollars)		
Canadian financial institutions	**69**	1
European financial institutions	**13**	-
	82	1

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

Fair Value of Derivatives

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

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any derivative instruments classified as Level 1.

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

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

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of derivative and the nature of the underlying risk, the Company uses observable market prices (interest and natural gas) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

At December 31, 2013, the Company had Level 2 derivative assets with fair value of $82 million (2012 - $1 million), and Level 2 derivative liabilities with fair value of nil (2012 - $2 million).

The Company's policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at December 31, 2013 or 2012.

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 carried at cost of $825 million at December 31, 2013 (2012 - $825 million), which approximates its fair value and redemption value.

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, 2013, the Company's long-term debt had a carrying value of $2,799 million (2012 - $2,387 million) and a fair value of $3,161 million (2012 - $2,994 million).

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

18. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**260**	261	206
Federal statutory income tax rate	**15.0%**	15.0%	16.5%
Federal income taxes at statutory rate	**39**	39	34
Increase/(decrease) resulting from:			
Provincial and state income taxes	**19**	18	16
Effects of rate regulated accounting	**(5)**	(7)	-
Non-taxable intercompany distributions	**(9)**	(9)	(10)
Legislative changes and other rate differentials	**-**	8	-
Intercompany sale of investment[1]	**-**	3	-
Other[2]	**(1)**	1	(5)
Income taxes before discontinued operations	**43**	53	35
Effective income tax rate	**16.5%**	20.3%	17.0%

1 *In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund. As the transaction occurred between entities under common control of Enbridge, the intercompany gain realized as a result of this transfer was eliminated, although cash income taxes of $5 million remained as a charge to earnings.*

2 *Included in "Other" are miscellaneous permanent differences. These include the tax effect of items such as non-deductible meals & entertainment, and change in prior year estimates arising from the filing of tax returns in respect of the prior year.*

Comparative figures within the income tax reconciliation for 2012 and 2011 have been revised to conform to the presentation followed for the current year. In 2013, a preferable presentation format was adopted which calculates expected taxes using a federal statutory rate as opposed to a combined federal and provincial rate. This format is preferable as it is more commonly used by companies following U.S. GAAP.

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,	**2013**	2012
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(320)**	(317)
Financial derivatives	**(25)**	-
Deferrals	**(13)**	(23)
Regulatory assets	**(56)**	(52)
Other	**(2)**	-
Total deferred income tax liabilities	**(416)**	(392)
Deferred income tax assets		
Financial derivatives	**-**	4
Retirement and postretirement benefits	**23**	23
Other	**1**	8
Total deferred income tax assets	**24**	35
Net deferred income tax liabilities	**(392)**	(357)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 7)*	**2**	5
Deferred amounts and other assets *(Note 9)*	**1**	-
Total deferred income tax assets	**3**	5
Liabilities		
Deferred income taxes	**(395)**	(362)
Total deferred income tax liabilities	**(395)**	(362)
Net deferred income tax liabilities	**(392)**	(357)

The Company has assessed all tax positions. As a result, no significant adjustments were required to be made to the income tax provisions for the year ended December 31, 2013.

The Company and its subsidiaries are subject to taxation in Canada. The Company is open to examination by certain tax authorities for the 2009 to 2013 tax years. The material jurisdictions in which the Company is subject to potential examinations include Canada (Federal and Ontario).

19. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company maintains a non-contributory basic pension plan that provides either defined benefit or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans that provide pension benefits in excess of the basic plan for certain employees.

A measurement date of December 31, 2013 was used to determine the plan assets and accrued benefit obligation for the pension plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. In 2013, mortality assumptions were revised resulting in an increase to pension liabilities of $28 million. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recent actuarial valuation was September 1, 2013. The effective date of the next required actuarial valuation is September 1, 2016.

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

OTHER POSTRETIREMENT BENEFITS
The Company also provides OPEB, which primarily includes supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

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

	Pension		OPEB	
December 31,	**2013**	2012	**2013**	2012
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**905**	852	**112**	103
Service cost	**25**	21	**1**	2
Interest cost	**38**	37	**4**	4
Actuarial loss	**(52)**	33	**(16)**	5
Benefits paid	**(40)**	(37)	**(2)**	(3)
Other	**(1)**	(1)	**1**	1
Benefit obligation at end of year	**875**	905	**100**	112
Change in plan assets				
Fair value of plan assets at beginning of year	**782**	744	**7**	6
Actual return on plan assets	**84**	59	**1**	1
Employer's contributions	**38**	17	**3**	4
Benefits paid	**(40)**	(37)	**(2)**	(3)
Other	**2**	(1)	**-**	(1)
Fair value of plan assets at end of year	**866**	782	**9**	7
Underfunded status at end of year	**(9)**	(123)	**(91)**	(105)
Presented as follows:				
Deferred amounts and other assets *(Note 9)*	**7**	3	**1**	-
Accounts payable and other *(Note 11)*	**-**	-	**(4)**	(5)
Other long-term liabilities *(Note 13)*	**(16)**	(126)	**(88)**	(100)

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

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**5.0%**	4.3%	4.5%	**5.0%**	4.3%	4.5%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	3.5%	5.0%

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
(millions of Canadian dollars)						
Benefits earned during the year	**25**	21	16	**1**	2	1
Interest cost on projected benefit obligations	**38**	37	39	**4**	4	5
Actual return on plan assets	**(84)**	(59)	(15)	**(1)**	(1)	-
Actuarial loss	**(52)**	33	127	**(16)**	5	13
Difference between actual and expected return on plan assets						
Return on plan assets	**32**	10	(38)	**-**	-	-
Amortization of prior service costs	**1**	1	2	**-**	-	-
Amortization of actuarial loss	**80**	(3)	(110)	**18**	(4)	(13)
Net defined benefit costs on an accrual basis	**40**	40	21	**6**	6	6
Defined contribution benefit costs	**1**	1	1	**-**	-	-
Net benefit cost recognized on an accrual basis	**41**	41	22	**6**	6	6
Net amount recognized in OCI						
Net actuarial (gain)/loss[1]	**-**	-	-	**(14)**	4	13
Total amount recognized in OCI	**-**	-	-	**(14)**	4	13
Total net benefit cost on an accrual basis and amount recognized in OCI	**41**	41	22	**(8)**	10	19

1 *Unamortized actuarial losses included in AOCI, before tax, were nil relating to OPEB at December 31, 2013 (2012 - $14 million, 2011 - $10 million).*

The Company estimates that approximately $17 million related to pension plans and OPEB at December 31, 2013 will be reclassified into earnings in the next 12 months, as follows:

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	**-**	**-**	**-**
Actuarial Loss	**17**	**-**	**17**
	17	**-**	**17**

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 in future rates *(Note 5)*. For the year ended December 31, 2013, an offsetting regulatory asset of $3 million (2012 - $22 million) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

Pension and OPEB costs related to the period on an accrual basis are presented above and were initially expensed. However, there was a partially offsetting adjustment for pension and OPEB costs due to the regulatory mechanism in place. As a result, the net pension and OPEB expense primarily consisted of OEB approved pension and OPEB costs.

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

	Pension			OPEB		
Year ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**4.3%**	4.5%	5.7%	**4.3%**	4.5%	5.7%
Average rate of return on pension plan assets	**6.8%**	7.0%	7.3%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.5%**	3.5%	3.5%	**3.5%**	5.0%	5.0%

MEDICAL COST TRENDS

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

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	8.2%	4.3%	2029
Other medical and dental	4.5%	4.5%	-

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $12 million in the benefit obligation and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $10 million in the benefit obligation and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

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

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2013**	2012	**2013**	2012
Expected rate of return	**6.8%**	7.0%	**-**	-

Target Mix for Plan Assets

Equity securities	44.5%
Fixed income securities	40.0%
Other	15.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2013, the pension assets were invested in 55% (2012 - 60%) in equity securities, 36% (2012 - 37%) in fixed income securities and 9% (2012 - 3%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $18 million (2012 - $10 million) have been excluded from the table below.

December 31,	2013 Level 1[1]	2013 Level 2[2]	2013 Level 3[3]	2013 Total	2012 Level 1[1]	2012 Level 2[2]	2012 Level 3[3]	2012 Total
(millions of Canadian dollars)								
Pension Benefits								
Cash and cash equivalents	**12**	**-**	**-**	**12**	18	-	-	18
Fixed income securities								
Canadian government real return bonds	**62**	**-**	**-**	**62**	57	-	-	57
Canadian corporate bond index fund	**122**	**-**	**-**	**122**	109	5	-	114
Canadian government bond index fund	**115**	**-**	**-**	**115**	109	-	-	109
Canadian real return bond index fund	**2**	**-**	**-**	**2**	-	2	-	2
Corporate bonds and debentures	**3**	**-**	**-**	**3**	-	-	-	-
United States debt index fund	**1**	**-**	**-**	**1**	-	-	-	-
Equity								
Canadian equity securities	**70**	**-**	**-**	**70**	113	-	-	113
Canadian equity funds	**118**	**-**	**-**	**118**	4	59	-	63
United States equity securities	**1**	**-**	**-**	**1**	-	-	-	-
United States equity funds	**65**	**17**	**-**	**82**	58	13	-	71
Global equity funds	**142**	**55**	**-**	**197**	100	74	-	174
Infrastructure[4]	**-**	**-**	**29**	**29**	-	-	38	38
Real estate[5]	**-**	**-**	**38**	**38**	-	-	15	15
Forward currency contracts	**-**	**(4)**	**-**	**(4)**	-	(2)	-	(2)
OPEB								
Cash and cash equivalents	**-**	**-**	**-**	**-**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**3**	**-**	**-**	**3**	2	-	-	2
Equity								
United States equity fund	**3**	**-**	**-**	**3**	2	2	-	4
Global equity fund	**3**	**-**	**-**	**3**	-	-	-	-

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair value of the investment in United States Limited Partnership - Global Infrastructure Fund is established through the use of valuation models.
5 The fair value of the investment in Bentall Kennedy Prime Canadian Property Fund Ltd is established through the use of valuation models.

Changes in the net fair value of plan assets classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	2013	2012
Balance at beginning of year	**53**	44
Unrealized and realized gains	**4**	7
Purchases and settlements, net	**10**	2
Balance at end of year	**67**	53

PLAN CONTRIBUTIONS BY THE COMPANY

Year ended December 31,	Pension 2013	Pension 2012	OPEB 2013	OPEB 2012
(millions of Canadian dollars)				
Total contributions	**39**	18	**3**	4
Contributions expected to be paid in 2014	**56**		**5**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2014	2015	2016	2017	2018	2019-2023
(millions of Canadian dollars)						
Expected future benefit payments	44	46	48	50	52	285

20. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Accounts receivable and other	**(46)**	76	134
Gas inventories	**(41)**	54	11
Accounts payable and other	**35**	(32)	(103)
Other long-term liabilities[1]	**(34)**	(27)	(27)
	(86)	71	15

1 *Consists primarily of net costs for site removal and restoration activities.*

21. RELATED PARTY TRANSACTIONS

All related party transactions, other than those disclosed under Other Transactions, are provided in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
IPL System Inc.			
Dividend income	**63**	63	63
Interest expense	**27**	27	27
Enbridge			
Purchase of treasury and other management services	**38**	39	34
Tidal Energy Marketing Inc.			
Purchase of natural gas	**30**	11	17
Tidal Energy Marketing (U.S.) LLC			
Purchase of natural gas	**21**	2	2
Gazifère Inc.			
Revenue from wholesale service, including gas sales	**30**	25	28
Vector Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**24**	24	24
Vector Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**2**	2	2
Alliance Pipeline Limited Partnership (Canadian)			
Purchase of gas transportation services	**26**	25	25
Alliance Pipeline Limited Partnership (U.S.)			
Purchase of gas transportation services	**19**	18	18

The Company had related party balances as follows:

December 31,	**2013**	2012
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**2**	2
Note payable to affiliate company		
Enbridge (U.S.)	**15**	13
Other accounts receivable/(payable)		
Enbridge Pipelines Inc.	**(15)**	3
IPL System Inc.	**(15)**	-
Tidal Energy Marketing (U.S.) LLC	**(4)**	-
Enbridge	**(5)**	(7)
Tidal Energy Marketing Inc.	**(7)**	(2)
Gazifère Inc.	**5**	4

Financing Transactions

The Company has invested in Class D, non-voting, redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2013, the investment of $825 million (2012 - $825 million) in these shares resulted in a weighted average dividend yield of 7.6%.

At December 31, 2013, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% 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, 2013, interest paid amounted to $27 million (2012 - $34 million).

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

Treasury and Other Management Services

Enbridge provides treasury and other management services and charges the Company on a cost recovery basis.

Natural Gas Purchases

The Company has contracted for the purchase of natural gas from Tidal Energy Marketing Inc. and Tidal Energy Marketing (U.S.) LLC, related entities under common control, at prevailing market prices and under normal trade terms. Contractual obligations under these contracts are 2014 - $52 million and nil thereafter.

Wholesale Service

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

Gas Transportation Services

The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2014 - $74 million, 2015 to 2016 - $82 million, 2017 to 2018 - $16 million and thereafter - nil.

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

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

Other Transactions
In 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to the Fund, an affiliated entity under common control, for cash proceeds of $72 million *(Note 6)*.

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

22. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,010 million which are expected to be paid within the next five years and $649 million in total for years thereafter.

Minimum future payments under operating leases are estimated at $12 million in aggregate. Estimated annual lease payments for the years ended December 31, 2014 through 2018 are $4 million, $4 million, $3 million, $1 million and nil, respectively. Total rental expense for operating leases, classified in Operating and administrative expense, was $3 million for each of the years ended December 31, 2013, 2012 and 2011.

CONTINGENCIES

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

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

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

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

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

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2013 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

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

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

OTHER LITIGATON

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

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debenture
9.85% debenture

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

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

REGISTRAR AND PAYING AGENT

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

TRUSTEE

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

REGISTRAR AND TRANSFER AGENT

Group 3 Preference Shares
Computershare Investor Services Inc.
100 University Avenue, 8^{th} Floor
Toronto, Ontario, M5J 2Y1

CORPORATE GOVERNANCE

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

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

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

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

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

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

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

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 5, 2013), which is incorporated herein by reference.

ENBRIDGE GAS DISTRIBUTION INC.

(a subsidiary of Enbridge Inc.)

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2013

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 13, 2014 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Gas Distribution Inc. (the Company) as at and for the year ended December 31, 2013, which are prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements prepared and MD&A contained in the Company's Annual Report for the year ended December 31, 2012. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

In connection with the preparation of the Company's third quarter consolidated financial statements, an error was identified in the manner in which a component of gas commodity and distribution costs had been recorded. The matter related to the accounting true-up mechanism between actual gas commodity and distribution costs incurred and the regulator-approved price charged to customers. The error was not material to any of the Company's previously issued consolidated financial statements; however, as discussed in Note 4, Revision of Prior Period Financial Statements to the annual consolidated financial statements as at December 31, 2013, prior year comparative financial statements have been revised to reflect the effect of these revisions. As a result of this error, the Company remitted excess income taxes totaling $22 million to the Canada Revenue Agency (CRA) in relation to the 2010, 2011 and 2012 taxation years and over shared earnings with ratepayers under an earnings sharing mechanism in relation to 2010, 2011 and 2012. The Company expects that it will recover the tax overpayment from the CRA. The discussion and analysis included herein is based on revised financial results for the years ended December 31, 2012 and 2011, or other comparative periods as indicated.

OVERVIEW

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

The Company also owns and operates regulated and unregulated natural gas storage facilities in Ontario. Between August 2011 and December 2012, the Company owned and operated two unregulated solar projects located in Amherstburg, Ontario, through a 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg).

PERFORMANCE OVERVIEW

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars, except per share amounts)			
Earnings attributable to the common shareholder[1]	**215**	210	171
Earnings excluding the effect of weather[2]	**206**	233	170
Cash flow data			
Cash provided by continuing operations	**450**	543	488
Cash provided by discontinued operations	**-**	12	3
Cash used by investing activities	**(547)**	(391)	(443)
Cash provided/(used) by financing activities	**138**	(170)	(52)
Dividends			
Common share dividends declared	**200**	201	220
Dividends declared per common share	**1.37**	1.41	1.56
Preference share dividends declared	**2**	2	2
Dividends declared per preference share	**0.60**	0.60	0.60
Total revenues			
Gas commodity and distribution revenues	**2,221**	1,869	1,880
Transportation of gas for customers	**328**	345	421
Other revenue	**99**	202	103
Revenue from continuing operations	**2,648**	2,416	2,404
Revenue from discontinued operations	**-**	10	3
Total revenues	**2,648**	2,426	2,407
Total assets[3]	**8,379**	7,915	7,776
Total long-term liabilities[4]	**4,195**	4,218	4,091
Number of active customers[5] *(thousands)*	**2,065**	2,032	1,997
Heating degree days[6]			
Actual	**3,746**	3,194	3,597
Forecasted based on normal weather	**3,668**	3,532	3,602

1. *Includes earnings from discontinued operations of $4 million and $2 million for the years ended December 31, 2012 and 2011, respectively.*
2. *Earnings excluding the effect of weather is a non-GAAP measure that does not have any standardized meaning prescribed by U.S. GAAP. For more information on this non-GAAP measure see page 5.*
3. *Total assets at December 31, 2011 include $74 million of assets from discontinued operations.*
4. *Total long-term liabilities as at December 31, 2011 include $6 million of liabilities from discontinued operations.*
5. *Number of active customers is the number of natural gas consuming customers at the end of the year.*
6. *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the Greater Toronto Area.*

EARNINGS ATTRIBUTABLE TO THE COMMON SHAREHOLDER

The comparability of earnings attributable to the common shareholder is impacted by the transition from the Incentive Regulation (IR) methodology in effect in 2012 to the cost of service settlement and decision applicable to 2013 (the 2013 Settlement). The rate structure for 2013 retained the previous deemed equity level but provided for an increase in the allowed return on equity (ROE). The 2013 Settlement further retained the flow-through nature of the cost of natural gas supply and several other cost categories. The earnings sharing mechanism, which was previously in effect under IR, did not apply to the 2013 Settlement.

Earnings attributable to the common shareholder were $215 million for the year ended December 31, 2013 compared with $210 million for the year ended December 31, 2012. The increase was primarily due to colder weather, customer growth, the absence of earnings sharing in 2013 and higher Shared Savings Mechanism (SSM) revenue which results from exceeding targets on delivery of energy efficiency programs for promotion of energy efficient use of natural gas to customers. This was partially offset by a decrease in other revenue compared to the year ended December 31, 2012, as an $89 million regulatory asset related to other postretirement benefits (OPEB) was recognized in 2012. The 2013 Settlement established the right to recover the OPEB regulatory asset over a 20-year period commencing in 2013. Additional information about the impact of the recognition of the OPEB regulatory asset is included in Note 5 of the 2013 Annual Consolidated Financial Statements.

Earnings attributable to the common shareholder were $210 million for the year ended December 31, 2012 compared with $171 million for the year ended December 31, 2011. The increase was primarily due to the recognition of an OPEB regulatory asset, higher revenue related to pipeline optimization activities and customer growth. This was partially offset by warmer weather, higher income taxes, and higher depreciation and amortization expense.

EARNINGS EXCLUDING THE EFFECT OF WEATHER

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings attributable to the common shareholder	**215**	210	171
(Colder)/warmer than normal weather	**(9)**	23	(1)
Earnings excluding the effect of weather	**206**	233	170

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

Normal weather is the weather forecast by the Company in its distribution franchise area, using the forecasting methodology approved by the Ontario Energy Board (OEB). As part of its 2013 rate application, the Company forecast for the Greater Toronto Area (GTA) utilized a 10-year moving average method. The methodology was approved by the OEB as part of the 2013 Settlement.

Normal weather is a measure that is unique to the Company and does not have any standardized meaning. In addition, due to differing franchise areas, it is unlikely to be directly comparable to the impact of weather-normalized earnings that may be reported by other entities. Moreover, normal weather may not be comparable from year to year given that the forecasting models are updated annually to reflect the most recent weather data.

Earnings excluding the effect of weather were $206 million for the year ended December 31, 2013 compared with $233 million for the year ended December 31, 2012. The decrease primarily resulted from lower other revenue due to the recognition of an OPEB regulatory asset in the prior year. This was partially offset by customer growth, the absence of earnings sharing in 2013 and higher SSM revenue.

Earnings excluding the effect of weather were $233 million for the year ended December 31, 2012 compared with $170 million for the year ended December 31, 2011. The increase was primarily due to the recognition of an OPEB regulatory asset, higher revenue related to pipeline optimization activities and customer growth. This was partially offset by higher income taxes, and higher depreciation and amortization expense.

REVENUES

Revenues from continuing operations for the year ended December 31, 2013 were $2,648 million compared with $2,416 million for the year ended December 31, 2012. The increase in revenues from continuing operations was primarily due to colder weather, customer growth, higher commodity prices and higher SSM revenue. This was partially offset by a decrease in other revenue mainly due to the recognition of an OPEB regulatory asset in the prior year.

Revenues from continuing operations for the year ended December 31, 2012 were $2,416 million compared with $2,404 million for the year ended December 31, 2011. The increase in revenues from continuing operations was primarily due to the recognition of an OPEB regulatory asset, higher revenue related to pipeline optimization activities and customer growth, partially offset by warmer weather and lower natural gas prices.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company's shareholders and potential investors with information about the Company and its subsidiaries, including management's assessment of the Company's and its subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ''anticipate'', ''expect'', ''project'', ''estimate'', ''forecast'', ''plan'', ''intend'', ''target'', ''believe'' and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to: expected earnings/(loss); expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; estimated future dividends; and expected costs related to leak remediation and potential insurance recoveries.

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

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

NON-GAAP MEASURE

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

STRATEGY

The Company's vision is to become North America's leading energy distribution and services company.

To achieve its vision, the Company has outlined the following strategic objectives:

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

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

Operations safety and system integrity continues to be the Company's number one priority and sets the foundation for the Company's strategic plan. Core to this priority is the focus on system integrity, and environmental and safety programs, which charts the course for best-in-class practices.

RECENT DEVELOPMENTS

IR APPLICATION

In July 2013, the Company filed an application with the OEB for the setting of rates through a customized IR mechanism for the period of 2014 through 2018.

The objectives of the IR plan are as follows:

- reduce regulatory costs with less frequent hearings;
- provide incentives for improved efficiency;
- provide more flexibility for utility management; and
- provide for necessary infrastructure upgrades, safety and reliability projects and system growth.

As part of the OEB rate-setting process, the Company has been engaged in settlement negotiations with customer representatives regarding the applicable terms and conditions during January and February 2014. An OEB decision on the Company's application is anticipated by the second quarter of 2014.

EQUITY INJECTION BY PARENT COMPANY

In August 2013, the Company's parent company subscribed for and was issued an additional 8,319,468 common shares for proceeds of $150 million, which helped rebalance the Company's capital structure to be in alignment with the deemed equity ratio of 36%.

AGREEMENT WITH TRANSCANADA

In September 2013, the Company, along with Union Gas Limited and Gaz Metro Limited Partnership, announced an agreement with TransCanada Pipelines Limited intended to enable access to diverse and affordable natural gas supplies in Eastern Canada. The agreement has been submitted to the National Energy Board and is subject to regulatory approval.

GTA PROJECT
The Company plans to expand its natural gas distribution system in the GTA to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $700 million, the proposed GTA project will consist of two segments of pipeline and related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. The Company filed amended applications reflecting scope modifications with the OEB in February, April and July 2013. As a result of the July scope modification, the expected capital cost increased by approximately $100 million. OEB hearings were held in September and October 2013 and approval was received from the OEB in January 2014. Construction is targeted to start in late 2014, with completion expected by the end of 2015.

FRANKLIN COUNTY EXPANSION PROJECT
In July 2012, St. Lawrence received regulatory approval to expand its operations to Franklin County in New York State. The construction associated with the expansion began in August 2012 and the completion of the high pressure distribution line is slated for the second quarter of 2014. The total capital cost over five years, including several distribution systems, is estimated to be US$45 million, with expenditures to date of approximately US$38 million. The expansion is expected to add 4,400 potential customers to St. Lawrence's distribution system, which had 15,800 customers at December 31, 2013.

APPOINTMENT OF NEW PRESIDENT
Effective October 1, 2013, Mr. Glenn Beaumont was appointed as President of the Company. At the same time, Mr. Guy Jarvis, the Company’s previous President, was appointed Executive Vice President & Chief Commercial Officer, Liquids Pipelines, Enbridge Inc.

RESULTS OF OPERATIONS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Gas distribution margin	**1,069**	985	1,005
Other revenue	**99**	202	103
Operating and administrative expenses	**(454)**	(449)	(437)
Depreciation and amortization	**(304)**	(320)	(302)
Municipal and other taxes	**(42)**	(40)	(41)
Earnings sharing	**-**	(10)	(13)
Affiliate financing income	**63**	63	63
Interest expense	**(171)**	(170)	(172)
Income taxes	**(43)**	(53)	(35)
Earnings from continuing operations	**217**	208	171
Earnings from discontinued operations, net of tax	**-**	4	2
Earnings	**217**	212	173
Earnings attributable to the common shareholder	**215**	210	171

GAS DISTRIBUTION MARGIN
Gas distribution margin for the year ended December 31, 2013 increased by $84 million compared with the year ended December 31, 2012. The increase was primarily due to colder weather and customer growth.

The heating degree days reported in 2013 were 78 heating degree days colder compared with forecast heating degree days. On a weather-normalized basis, net gas distribution margin for the year ended December 31, 2013 would have been lower by $13 million (2012 - higher by $31 million). Weather, measured in heating degree days, was 3,746 heating degree days for the year ended December 31, 2013 compared with 3,194 heating degree days for the year ended December 31, 2012.

Gas distribution margin for the year ended December 31, 2012 decreased by $20 million compared with the year ended December 31, 2011. The decrease was primarily due to warmer weather, partially offset by customer growth and higher distribution charges.

The heating degree days reported in 2012 were 338 heating degree days warmer compared with forecast heating degree days. On a weather-normalized basis, net gas distribution margin for the year ended December 31, 2012 would have been higher by $31 million (2011 - lower by $1 million). As experienced in 2011, there was significant variability in the 2012 heating degree day profiles of the geographical regions in which the Company operates. Weather, measured in heating degree days, was 3,194 heating degree days for the year ended December 31, 2012 compared with 3,597 heating degree days for the year ended December 31, 2011.

OTHER REVENUE

Other revenue for the year ended December 31, 2013 decreased by $103 million compared with the year ended December 31, 2012. The decrease was primarily due to the recognition of an OPEB regulatory asset in the prior year, adjustments to reflect developments in the 2012 Earnings Sharing Mechanism regulatory proceedings, lower oil revenue and lower revenue from the management of fee-for-service energy efficiency initiatives. This was partially offset by higher SSM revenue.

Other revenue for the year ended December 31, 2012 increased by $99 million compared with the year ended December 31, 2011. The increase was primarily due to the recognition of an OPEB regulatory asset and higher revenue related to pipeline optimization activities and unregulated storage operations.

OPERATING AND ADMINISTRATIVE

Operating and administrative expenses for the year ended December 31, 2013 increased by $5 million compared with the year ended December 31, 2012. Operating and administrative expenses for the year ended December 31, 2012 increased by $12 million compared with the year ended December 31, 2011. The increases in both years were primarily due to higher pension costs and higher operational, system integrity and safety costs, partially offset by lower customer support related costs.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the year ended December 31, 2013 decreased by $16 million compared with the year ended December 31, 2012. The decrease primarily resulted from the application of new depreciation rates which came into effect on January 1, 2013, pursuant to a depreciation study commissioned by the Company in 2012. The revised rates formed part of the 2013 Settlement. This was partially offset by an increase in the overall asset base resulting from improvements to the distribution system and customer growth projects. Additional information about the impact of the revised rates is included in Note 3 of the 2013 Annual Consolidated Financial Statements.

Depreciation and amortization expense for the year ended December 31, 2012 increased by $18 million compared with the year ended December 31, 2011. The increase was primarily due to higher overall asset bases resulting from improvements to the distribution system and customer growth projects.

EARNINGS SHARING

Under IR in 2011 and 2012, earnings sharing represented the estimated customer portion of regulated earnings in excess of 100 basis points above the allowed utility ROE threshold applicable to the Company, relating to the approved IR formula for the 2011 and 2012 fiscal years and relating to the OEB's ROE policy guideline in effect prior to December 2009. Earnings sharing for 2012 was $3 million lower compared to 2011 primarily due to lower regulated earnings. Earnings sharing did not apply to the 2013 rate year.

INTEREST EXPENSE

Interest expense for the year ended December 31, 2013 increased by $1 million compared with the year ended December 31, 2012. The increase was primarily due to the issuance of medium term notes (MTNs) and interest on regulatory deferrals as a result of the prior period revision discussed in Note 4, Revision of Prior Period Financial Statements to the audited consolidated financial statements as at and for the year ended December 31, 2013.

Interest expense for the year ended December 31, 2012 decreased by $2 million compared with the year ended December 31, 2011. The decrease was primarily due to a lower interest rate on a portion of replaced long-term debt and lower commitment fees on the credit facility.

INCOME TAXES

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**260**	261	206
Income taxes	**43**	53	35
Effective tax rate (%)	**16.5**	20.3	17.0

The effective tax rate for the year ended December 31, 2013 was lower compared with the year ended December 31, 2012. The decrease was due to a revaluation of the deferred tax liabilities in the prior year as a result of an increase in the Ontario income tax rate in 2012 and a capital gain from the sale of Project Amherstburg in 2012. The decrease was partially offset by temporary differences relating to regulatory property, plant and equipment and intangible assets.

The effective tax rate for the year ended December 31, 2012 was higher compared with the year ended December 31, 2011. The increase was due to the revaluation of the deferred income tax liabilities as a result of a 1.5% increase in the Ontario income tax rate in 2012 and a capital gain from the sale of Project Amherstburg in 2012, partially offset by temporary differences relating to regulatory property, plant and equipment and intangible assets.

RATE REGULATION

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

For the year ended December 31, 2013, the Company's rates were set on a cost of service basis pursuant to the 2013 Settlement. For the years ended December 31, 2012 and 2011, the Company's annual rates were set using a revenue per customer cap IR methodology which adjusted revenues, and consequently rates, annually and relied on an annual process to forecast volume and customer additions. St. Lawrence's rates were set on a cost of service basis for the years ended December 31, 2013, 2012 and 2011.

IMPACT OF RATE REGULATION

The Company follows U.S. GAAP, which may differ in their application to the Company's regulated operations, as compared to non-regulated businesses. These differences occur when the Regulators render their decisions on the Company's rate applications, and generally involve the timing of revenue and expense recognition to ensure that the actions of the Regulators, which create assets and liabilities, have been reflected in the consolidated financial statements.

Accounting Standards Codification 980 (ASC 980), *Regulated Operations*, requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the Company's consolidated financial statements. Detailed disclosure on rate regulation is included in Note 5 to the 2013 Annual Consolidated Financial Statements.

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

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

There are other areas where the determination of the amounts to be recovered in current rates is different from the determination that would be reported by a non-regulated business, and the Company records those items on the same basis as they are recovered in rates. Future removal and site restoration reserves, income taxes and employee future benefits are the most significant such examples.

The recognition or omission of these items is based on an expectation of the future actions of the Regulators. For example, the liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. However, the regulated utility operations of the Company recover income tax expense based on the taxes payable method as approved by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company’s ability to pay/collect the amounts in the future through rates.

To the extent that the Regulators’ future actions are different from current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

LIQUIDITY AND CAPITAL RESOURCES

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

An $800 million shelf prospectus was filed in January 2013 and will be effective for a 25 month period.

In 2010, the Company issued $200 million of new 10 year MTNs at an interest rate of 4.04% and $200 million of new 40 year MTNs at an interest rate of 4.95%. In 2011, the Company issued an additional $100 million of MTNs under the same terms as the $200 million 40 year MTN pricing supplement issued in 2010 at an interest rate of 4.95%. In 2013, the Company issued $200 million of new 30 year MTNs at an interest rate of 4.50% and an additional $200 million of MTNs under the same terms as the $200 million 10 year MTN pricing supplement issued in 2010 at an interest rate of 4.04%.

In August 2013, the Company extended the term out date of its $700 million committed line of credit for an additional year to August 2014, with a maturity date in August 2015.

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, 2013.

	Maturity Dates	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc.	2015	**700**	**370**	**330**
St. Lawrence Gas Company, Inc.	2019	**13**	**12**	**1**
Total credit facilities		**713**	**382**	**331**

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

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

December 31,	**2013**	2012
(millions of Canadian dollars)		
Cash and cash equivalents	**44**	3
Accounts receivable and other	**706**	605
Gas inventories	**382**	341
Bank indebtedness	**(4)**	(5)
Short-term borrowings	**(389)**	(596)
Accounts payable and other	**(769)**	(730)
Working capital	**(30)**	(382)

When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. At December 31, 2013, this ratio was 2.40 (2012 - 2.04). The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test.

OPERATING ACTIVITIES

Cash provided by operating activities was $450 million for the year ended December 31, 2013 compared with $555 million in 2012. The decrease in cash provided was primarily due to fluctuations in working capital resulting from the impacts of weather and natural gas prices. The cash outflows within operating activities were partially offset by proceeds on the settlement of certain derivative instruments related to the MTNs issued in 2013.

Cash provided by operating activities was $555 million for the year ended December 31, 2012 compared with $491 million in 2011. The increase primarily resulted from lower net settlements on purchase gas variances owing to customers compared to 2011.

INVESTING ACTIVITIES

Cash used for investing activities was $547 million for the year ended December 31, 2013 compared with $391 million in 2012. The increase in cash used was primarily due to higher comparative capital spending on improvements to the distribution system and customer growth projects.

Cash used for investing activities was $391 million for the year ended December 31, 2012 compared with $443 million in 2011. The decrease in cash used was primarily due to cash proceeds from the sale of Project Amherstburg and the completion of construction of a technical training facility in 2011. This was partially offset by higher comparative capital spending on improvements to the distribution system and customer growth projects.

CAPITAL EXPENDITURES

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
System improvements and upgrades	**298**	199	159
System expansion	**167**	157	140
Computers and communication equipment	**39**	43	38
Unregulated storage	**1**	1	32
Solar assets (Project Amherstburg)	**-**	-	68
Other	**81**	79	106
Total capital expenditures	**586**	479	543

The Company's existing distribution network consists of approximately 37,000 kilometres of underground natural gas mains and services. To support continuing customer growth, expansion of the network on an ongoing basis is required in addition to capital improvements.

The Company expects to spend approximately $690 million in 2014 on capital projects and maintenance. Annual capital expenditures in recent years have averaged approximately $470 million.

Major 2014 capital projects include the GTA project and a Work Asset Management Solution program. The net planned liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently approved capital projects and to provide flexibility for new investment opportunities.

FINANCING ACTIVITIES

Cash provided by financing activities was $138 million for the year ended December 31, 2013 compared with cash used of $170 million in 2012. The increase in cash provided was primarily due to the issuance of MTNs and common shares during the year, partially offset by higher net repayments of short-term borrowings.

Cash used for financing activities was $170 million for the year ended December 31, 2012 compared with $52 million in 2011. The increase was primarily due to lower borrowings and the absence of debt repayments in 2012, partially offset by lower dividend payments compared to 2011.

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

PREFERENCE SHARES

Floating adjustable cumulative cash dividends on the Group 3, Series D preference shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preference shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case. As at December 31, 2013, no preference shares have been redeemed.

On July 1, 2014, 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, 2014 and every five years thereafter.

Outstanding Share Data[1]

	Number
Preference Shares, Group 3, Series D, Fixed/Floating Cumulative Redeemable Convertible	4,000,000
Common shares	150,664,582

1. Outstanding share data information is provided as at February 13, 2014.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

The following chart outlines significant changes in the consolidated statements of financial position between December 31, 2012 and December 31, 2013.

Consolidated Statements of Financial Position Category	Increase/ (Decrease)	Explanation
(millions of Canadian dollars)		
Accounts receivable and other	101	Primarily due to higher sales volumes as a result of colder weather during the last month of the quarter and higher natural gas prices.
Property, plant and equipment, net	337	Primarily due to capital additions relating to distribution system improvements and customer growth, partially offset by depreciation.
Short-term borrowings	(207)	Primarily due to lower working capital needs and repayments of short-term borrowings using cash and cash equivalents generated from operations.
Long-term debt (including current portion)	412	Due to MTN issuances during the year.
Common shares	150	Due to a common share issuance during the year.

GAS HELD ON BEHALF OF TRANSPORTATION SERVICE CUSTOMERS

Transportation service customers source their natural gas supplies independently or through a broker and their estimated consumption is delivered into the Company's system evenly throughout the year. However, the consumption pattern varies from the even natural gas delivery pattern. Depending on the consumption/replenishment cycle, certain volumetric imbalances typically result whereby the Company either holds natural gas on behalf of transportation service customers or such customers have consumed more natural gas than the amount delivered to the Company. Specific defined parameters are in place and are monitored carefully to ensure that the volume of such imbalances does not exceed certain threshold levels. Customer accounts beyond these defined threshold levels incur penalties. All volume imbalances are trued up annually. The Company also has strict credit policies in place to mitigate this risk.

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

CONTINGENCIES AND COMMITMENTS

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

FORMER MANUFACTURED COAL GAS PLANT SITES

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

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

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

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

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

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2013 fiscal years, the OEB approved the establishment of deferral accounts, but added that the issue as to whether customers should be responsible for some or all of the possible claims and related costs has yet to be determined.

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

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

OTHER LITIGATION

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

CONTRACTUAL OBLIGATIONS

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

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt[1]	2,794	400	3	203	2,188
Gas transportation and storage contracts	3,212	1,024	1,060	599	529
Loans from affiliate company[1]	375	-	-	-	375
Customer care service contracts[2]	245	59	122	64	-
Right-of-way commitments[3]	130	2	4	4	120
Capital commitments	72	46	24	2	-
Operating leases	12	4	7	1	-
Pension obligations[4]	56	56	-	-	-
Total contractual obligations	6,896	1,591	1,220	873	3,212

1. *Excludes interest. Changes to the planned funding requirements dependent on the terms of any debt re-financing agreements.*
2. *In 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*
3. *Right-of-way payments are estimated to be approximately $2 million per year for the remaining life of all storage reservoirs, which has been assumed to be 60 years for purposes of calculating the amount of future minimum commitments beyond 2018.*
4. *Assumes only required payments will be made into the pension plans. Contributions are made in accordance with the independent actuarial valuations as of December 31, 2013. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

QUARTERLY FINANCIAL INFORMATION[1]

2013[1]	**Q1**	**Q2**	**Q3**	**Q4**	**Total**
(millions of Canadian dollars)					
Revenues	**1,027**	**472**	**335**	**814**	**2,648**
Earnings attributable to the common shareholder[2]	**98**	**31**	**1**	**85**	**215**
Warmer/(colder) than normal weather (after-tax impact)	**6**	**(2)**	**-**	**(13)**	**(9)**

2012[1]	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars)					
Revenues[3]	900	425	303	788	2,416
Earnings attributable to the common shareholder[2,4]	64	29	(4)	121	210
Warmer/(colder) than normal weather (after-tax impact)	24	-	-	(1)	23

1. *Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2. *Earnings attributable to the common shareholder for the 2012 comparative periods and for the three months ended March 31, 2013 and June 30, 2013 have been revised. See Note 4 to the 2013 Annual Consolidated Financial Statements.*
3. *Excludes revenues from discontinued operations of $1 million, $4 million, $4 million and $1 million for the three months ended March 31, 2012, June 30, 2012, September 30, 2012 and December 31, 2012, respectively.*
4. *Includes earnings from discontinued operations of nil, $2 million, $2 million and nil for the three months ended March 31, 2012, June 30, 2012, September 30, 2012 and December 31, 2012, respectively.*

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

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

Earnings for a given quarter in two successive years may vary significantly primarily due to potentially varying weather patterns. Specifically, periods of colder than normal weather would typically result in higher earnings compared to periods of warmer than normal weather. As a result, a meaningful comparison can only be achieved after adjusting earnings for the impact of weather.

Further, as a result of continued changes in customer billing to increase the fixed charge portion and decrease the per unit volumetric charge, a portion of revenues and earnings will shift from the colder winter quarters progressively to the warmer summer quarters, with no material impact on full year revenue and earnings. This change will also impact the comparability of a given quarter from year to year.

FOURTH QUARTER 2013 HIGHLIGHTS

Earnings attributable to the common shareholder were $85 million for the three months ended December 31, 2013 compared with $121 million for the same period in 2012. The decrease primarily resulted from lower other revenue due to the recognition of an OPEB regulatory asset in the fourth quarter of 2012, partially offset by colder weather and higher SSM revenue.

Earnings attributable to the common shareholder were $121 million for the three months ended December 31, 2012 compared with $34 million for the same period in 2011. The increase was primarily due to the recognition of an OPEB regulatory asset, lower operating and administrative expenses and colder weather. This was partially offset by higher income taxes and higher depreciation and amortization expense during the period.

RELATED PARTY TRANSACTIONS

The Company had transactions with related parties during the year. Amounts are invoiced on a monthly basis and are usually due and paid on a quarterly basis.

IPL System Inc. The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliated company under common control. At December 31, 2013, the investment of $825 million in these shares resulted in a weighted average dividend yield of 7.60%. For the year ended December 31, 2013, dividends received amounted to $63 million (2012 - $63 million) with an outstanding receivable balance of $5 million at December 31, 2013 (2012 - $5 million).

IPL System Inc. advanced the Company $375 million ($200 million at 6.85% and $175 million at 7.50%) repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable preference shares of the Company. For the year ended December 31, 2013, interest paid amounted to $27 million (2012 - $27 million) with an outstanding payable balance of $2 million at December 31, 2013 (2012 - $2 million).

Enbridge (U.S.), an affiliated company under common control, advanced St. Lawrence $15 million (2012 - $13 million) at the LIBOR rate plus 0.55%, payable on demand.

Enbridge, the ultimate parent company, provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services. Charges incurred for the year ended December 31, 2013 were $38 million (2012 - $39 million) with an outstanding payable balance of $5 million at December 31, 2013 (2012 - $7 million).

Tidal Energy Marketing Inc., an affiliated company under common control, sells natural gas to the Company at prevailing market prices and under normal trade terms. Total charges for the year ended December 31, 2013 were $30 million (2012 - $11 million) with an outstanding payable balance of $7 million at December 31, 2013 (2012 - $2 million).

Tidal Energy Marketing (U.S.) LLC, an affiliated company under common control, sells natural gas to the Company at prevailing market prices and under normal trade terms. Total charges for the year ended December 31, 2013 were $21 million (2012 - $2 million) with an outstanding payable balance of $4 million at December 31, 2013 (2012 - nil).

Gazifère Inc., an affiliated company under common control, obtains gas procurement and transportation services from the Company. These services are pursuant to a contract negotiated between the two companies and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie. Total revenues for the year ended December 31, 2013 were $30 million (2012 - $25 million) with an outstanding receivable of $5 million at December 31, 2013 (2012 - $4 million).

Vector Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2013 were $24 million (2012 - $24 million) with an outstanding payable of nil at December 31, 2013 (2012 - nil).

Vector Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2013 were $2 million (2012 - $2 million) with an outstanding payable of nil at December 31, 2013 (2012 - nil).

Alliance Pipeline Limited Partnership (Canadian), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2013 were $26 million (2012 - $25 million) with an outstanding payable of nil at December 31, 2013 (2012 - nil).

Alliance Pipeline Limited Partnership (U.S.), a related entity partially owned by an affiliated company under common control, provides natural gas transportation services to the Company. Total charges for the year ended December 31, 2013 were $19 million (2012 - $18 million) with an outstanding payable of nil at December 31, 2013 (2012 - nil).

Other Transactions
The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is

charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates. At December 31, 2013, the Company had an outstanding payable of $15 million to Enbridge Pipelines Inc. (2012 - $3 million receivable) and an outstanding payable of $15 million to IPL System Inc. (2012 - nil).

In December 2012, the Company sold its 99.9% limited partnership interest in Project Amherstburg to Enbridge Income Fund, an affiliated entity under common control, for cash proceeds of $72 million.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Company has formal risk management policies, procedures and systems designed to mitigate the risks described below. In addition, the Company performs an annual corporate risk assessment to scan its environment for all potential risks. Risks are ranked based on severity and likelihood and results are considered in the Company's strategic and operating plans. Through this process, a range of ongoing mitigants are identified and implemented.

REGULATORY RISK

The Company's operations are regulated and are subject to regulatory risk. The Company retains dedicated professional staff and maintains strong relationships with customers, interveners and regulators to help minimize regulatory risk.

In 2013, the Company's rates were approved by the OEB as part of the 2013 Settlement within a cost of service regulatory model. The OEB approved the ROE that the Company is permitted to charge in rates within the cost of service model, in addition to various other cost projections in relation to the utility's operations. The OEB Approved ROE is based on the OEB's Cost of Capital guidelines as applicable to the Company. The Company is also permitted by the OEB to recover costs considered within the scope of various deferral and variance accounts in relation to items for which costs cannot be accurately forecast. To the extent that costs that fall outside of those approved by the OEB within rates and permitted within the scope of approved deferral and variance accounts, the Company is at risk.

The Company does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the Regulators (including risk management costs for St. Lawrence). This difference is deferred as a receivable from or payable to customers until the Regulators approve its refund or collection. The Company monitors the balance and its potential impact on customers and will request interim rate relief that will allow the Company to recover or refund the natural gas cost differential.

The Company, excluding St. Lawrence, has a quarterly rate adjustment mechanism in place that allows for the quarterly adjustment of rates to reflect changes in natural gas prices. Adjustments are subject to prior approval by the OEB.

VOLUME RISKS

Since customers are billed on both a fixed charge and on a volumetric basis, the Company's ability to collect its total revenue depends in large part on achieving the forecast distribution volume established in the rate-making process. Volume forecasts are reviewed and approved by the OEB annually.

Variations in volumetric consumption depend on four key variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers.

Weather is a significant driver of delivery volumes, given that a significant portion of the Company's customer base uses natural gas for space heating. Weather, measured in terms of heating degree days, can have a direct impact on earnings of the Company as noted below. Heating degree days is a measure of coldness, calculated as the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius.

Factor	Incremental change	Approximate incremental impact
Weather	18 heating degree days	1.6 billion cubic feet
Volume	1 billion cubic feet	$1.2 million (after-tax)

An unusual distribution pattern of heating degree days during the year may impact the sensitivity described above. Heating degree days are fully effective, typically in the peak winter months, when their occurrence directly impacts the consumption pattern by a similar magnitude.

Distribution volume may also be impacted by increased adoption of energy efficient technologies, including more efficient building construction. In addition, conservation efforts by customers can further contribute to the decline in annual average consumption.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 81% (2012 - 79%) of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

There may be circumstances where the Company attains its total forecast distribution volume, but revenues are different from forecast as a result of other variables such as the mix between the residential, commercial and industrial sectors.

The Company remains at risk for the actual versus forecast large volume contract commercial and industrial volumes; however, general service volume risk is mitigated for both ratepayers and the Company through the average use true-up variance account. This variance account records the difference between forecast and actual weather normalized general service average uses, and trues up for the difference, through either a collection or repayment to customers. All parties are kept whole to the weather normalized general service volumetric forecast.

MARKET PRICE RISK

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

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them. The Company uses qualifying derivative instruments to manage some of the risks noted below.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed–receive floating interest rate swaps and options are used to mitigate the volatility of short-term interest rates on interest expense incurred on variable rate debt.

The Company's earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to mitigate the Company's exposure to long-term interest rate variability on select forecast term debt issuances.

Foreign Exchange Risk

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

Natural Gas Price Risk
Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. In compliance with the directive of the OEB, fluctuations in natural gas prices are borne by the customer, therefore, the net exposure to the Company is nil.

The Effect of Derivative Instruments on the Consolidated Statements of Earnings and Comprehensive Income
The following table presents the effect of cash flow hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Interest rate contracts	**109**	(1)	(2)
	109	(1)	(2)
Amount of loss reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**(2)**	(2)	(3)
	(2)	(2)	(3)
Amount of gain reclassified from AOCI to earnings *(ineffective portion)*			
Interest rate contracts[1]	**2**	-	-
	2	-	-

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

CREDIT RISK
Exposure to credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms, including obtaining additional security, to minimize the consequences of the risk of default on receivables.

The Company minimizes credit risk with regard to derivative counterparties by entering into risk management transactions only with institutions that possess solid investment grade credit ratings or which have provided the Company with an acceptable form of credit protection. The Company has no significant credit concentration with any single counterparty.

LIQUIDITY RISK
Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations and the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains a current shelf prospectus with securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2013. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

FAIR VALUE MEASUREMENTS

The Company's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The Company also discloses the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties to settle these instruments at the reporting date. The fair value of cash and cash equivalents, bank overdraft, and short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

The Company's investment in IPL System Inc., an affiliate company, is carried at cost of $825 million at December 31, 2013 (2012 - $825 million), which approximates its fair value and redemption value. At December 31, 2013, the Company's long-term debt had a carrying value of $2,799 million (2012 - $2,387 million) and a fair value of $3,161 million (2012 - $2,994 million).

Additional information about the Company's risk management and financial instruments is included in Note 17 of the 2013 Annual Consolidated Financial Statements.

GENERAL BUSINESS RISKS

Upstream Supply or Transport Failure

The Company's ability to deliver natural gas to its customers on demand is dependent on adequate supply being transported on third party transmission pipelines to its franchise. While the Company has received reliable service from its upstream service providers, a large supply or pipeline disruption on a very cold day has the potential to cause service disruption. The Company procures supply and transport from third party suppliers and pipelines to meet design winter conditions as approved by its regulator and diversifies its procurement to the extent possible.

Network Operating Risk

The Company's network is exposed to operational risks such as accidental damage to mains and service lines, corrosion leaks in mains and service lines, malfunction of compression, regulation and measurement equipment and other issues that can lead to unplanned natural gas escapes and outages. Leaks in the distribution system are an inherent risk of operations. Surveillance, maintenance and repair programs as well as the phased replacement of targeted pipes significantly reduces the exposure. In 2012, the Company completed its cast iron replacement and bare steel main replacement program.

Other operating risks include: the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond the control of the distribution network. The occurrence or continuance of any of these events could increase the cost of operating the Company's distribution network or reduce revenues, thereby impacting earnings.

The Company has extensive programs to manage pipeline integrity, which include leak survey, corrosion survey and the use of in-line inspection tools for high stress pipelines. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as the need is identified. The Company also maintains comprehensive insurance coverage for significant pipeline events and has a security program designed to reduce security-related risks. While the Company considers the level of insurance to be adequate, it may not be sufficient to cover all potential losses.

Environmental, Health and Safety Risk

The Company's operations and facilities are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. The Company's facilities, or facilities to which it provides operating services, could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. The Company could also incur liability in the future for environmental contamination associated with past and present activities and properties. The facilities and distribution network must maintain a number of environmental and other permits from various governmental authorities in order to operate and these facilities and the distribution network are subject to inspection from time to time. Failure to maintain compliance with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. Compliance with current and future environmental laws and regulations, which are likely to become more stringent over time, including those governing greenhouse gas (GHG) emissions, may impose additional capital costs and financial expenditures and affect the demand for the Company's services, which could adversely affect operating results and profitability. The Company could be targeted by environmental groups attempting to draw attention to GHG emissions.

The Company participates in a comprehensive insurance program which is maintained by Enbridge for its subsidiaries and affiliates. The program includes commercial liability insurance coverage and coverage for environmental incidents, taking into account coverage levels considered customary for its industry and the insurance market at the time of renewal. In the unlikely event multiple insurable incidents exceeding coverage limits are experienced by Enbridge subsidiaries or affiliates within the same insurance period, the total insurance coverage will be allocated on an equitable basis.

Public, Worker and Contractor Safety

Several of the Company's pipeline systems run adjacent to populated areas and a major incident could result in injury to members of the public. A public safety incident could result in reputational damage to the Company, material repair costs or increased costs of operating and insuring the Company's assets. In addition, given the natural hazards inherent in the Company's operations, its workers and contractors are often subject to personal safety risks.

Safety and operational reliability are the most important priorities at the Company. The Company's mitigation efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its strategic plan and emergency response preparedness. The Company believes in a safety culture where safety incidents are not tolerated by employees and contractors and has established a target of zero incidents.

Climate Change Legislation

Federal and Provincial carbon regulations remain in development. With the withdrawal of Canada from the Kyoto protocol, sector specific carbon related regulations may develop. It is currently unclear how natural gas distributors will be specifically treated.

Ontario is a signatory to the Western Climate Initiative and is currently developing proposed GHG reduction programs with stakeholder consultations. An implementation date has not been specified. The Company reports GHG emissions from combustion sources only in Ontario, and all reported data is verified by a third party. There were no issues identified for the 2013 reporting year. The Company continues to monitor developments and attend stakeholder consultations in Ontario.

The Company has successfully deployed a carbon data management system to help with the data capture and mandatory and voluntary reporting needs of the Company. The Company continues to publicly report its GHG emissions and will continue to develop internal procedures to identify operationally related GHG reductions.

Public Opinion
Public opinion or reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Potential impacts of a negative public opinion may include loss of business, legal action, increased regulatory oversight and costs.

Reputation risk often arises as a consequence of some other risk event, such as operating, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations with an emphasis on the prevention of any incidents;
- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- having strong corporate governance practices, including a Statement on Business Conduct, with which all employees are required to certify their compliance on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's Corporate Social Responsibility Policy, Climate Change Policy, Aboriginal and Native American Policy and initiatives such as the Neutral Footprint Initiative).

Information Systems Incident
The Company's infrastructure, applications and data are becoming more integrated, creating an increased risk a failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activity targeting industrial control systems. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems. Over the past year, the Company has continued to broaden the scope of its systems security with increased mitigation activities focused on the prevention, detection and necessary response to any potential systems security incident. Additionally, to increase accountability in relation to systems security, all information technology security operations in the Company are consolidated under one leadership structure to increase consistency and compliance with the Company's security requirements.

CRITICAL ACCOUNTING ESTIMATES

REVENUE RECOGNITION
The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced.

DEPRECIATION
Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2013 of $5,869 million (2012 - $5,532 million), or 70% of total assets (2012 - 70%), is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

These depreciation rates are reviewed through periodic depreciation studies conducted by an external consulting firm that makes an objective assessment of the useful lives of the Company's property, plant and equipment. The depreciation rates used by the Company are subject to approval by the OEB for rate setting purposes, which may not always reflect the recommendations of the latest depreciation study. The last such study was completed in 2012. The external consulting firm also provides a framework for the Company's calculation of the estimate of the net cumulative amount collected from customers for future site removal and restoration of property, plant and equipment.

REGULATORY ASSETS AND LIABILITIES

The Regulators exercise statutory authority over matters such as construction, rates and rate-making, and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities. Also, the Company records regulatory assets and liabilities to recognize the economic effects of the actions of the Regulators. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. On refund or recovery of this difference, no earnings impact is recorded. Effectively, the consolidated statement of earnings captures only the approved costs and the related revenue rather than the actual costs and related revenue. As of December 31, 2013, the Company's regulatory assets totaled $366 million (2012 - $434 million) and regulatory liabilities totaled $992 million (2012 - $987 million). To the extent that the Regulators' future actions differ from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded.

POSTRETIREMENT BENEFITS

The Company maintains pension plans, which provide non-contributory defined benefit and/or defined contribution pension benefits to the majority of its employees and OPEB to eligible retirees.

Pension costs and obligations for the defined benefit pension plans are determined using the projected benefit method. This method involves complex actuarial calculations using several assumptions including discount rates, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. However, there is significant measurement uncertainty incorporated into the actuarial valuation process. For example, there is no assurance that the pension plan will be able to earn the assumed rate of return. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods.

The difference between the actual and expected return on plan assets was an excess of $32 million for the year ended December 31, 2013 (2012 - excess of $10 million) as disclosed in Note 19 to the 2013 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

Assuming no discretionary funding is made into the pension plans, funding in 2014 will be $56 million.

The following sensitivity analysis identifies the impact on the December 31, 2013 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	61	7	7	1
Decrease in expected return on assets	-	4	n/a	n/a
Decrease in rate of salary increase	(8)	(3)	-	-

CONTINGENT LIABILITIES

Provisions for claims filed against the Company are determined on a case by case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company, are detailed in the Commitments and Contingencies section of this report and are disclosed in Note 22 of the 2013 Annual Consolidated Financial Statements.

REGULATORY GOVERNANCE

Undertakings

The Company, and its parent Enbridge, have entered into Undertakings with the Lieutenant Governor in Council for Ontario that commit Enbridge and the Company to certain obligations relating to the maintenance of common equity, as well as restrictions on diversification to the effect that the Company must not carry on, except through an affiliate or affiliates, any business activity other than the distribution, storage or transmission of natural gas without the OEB's prior approval. In compliance with these undertakings, the Company has obtained OEB approval to carry on the Natural Gas Vehicle Program, Agent Billing and Collection Program and Gas Sales and Oil Production activity.

In August 2006, the Government of Ontario approved changes to the Undertakings that allow the Company to provide services related to the promotion of electricity conservation, natural gas conservation and the efficient use of electricity, electricity load management, and the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources. In addition, the Company is allowed to engage in activities and provide services related to the local distribution of steam, hot and cold water in an initiative with Markham District Energy Inc., and pursuit of a pilot project for the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

In September 2009, Ontario's Minister of Energy and Infrastructure issued a Directive that permits the Company to own and operate stationary fuel cells, wind, water, biomass, biogas, solar and geothermal energy generation facilities up to 10 megawatts in capacity. The Company was also permitted to own and operate district and distributed energy systems, including facilities that produce power and thermal energy from a single source. Finally, the Minister's Directive permits the Company to own and operate assets that would assist the Government of Ontario in achieving its goals in energy conservation, including assets related to solar-thermal water and ground source heat pumps.

In the absence of the Minister's Directive, the Company's Undertakings to the Lieutenant Governor in Council would not have permitted the Company to engage in the foregoing activities directly. The Company plans to increase its role in this area and is looking to expand its efforts to explore and pursue alternative and/or renewable energy technologies subject to OEB approval, where appropriate.

While the Directive permits the Company to engage in such activities, in December 2009 the OEB determined that it would not allow such activities to be included in rate-making for the purposes of setting 2010 rates.

Affiliate Relationships Code

The Company is subject to the provisions of the OEB's Affiliate Relationships Code for Gas Utilities (the Code). The Code sets out the standards and conditions that govern the interaction between natural gas distributors, transmitters and storage companies in Ontario and their respective affiliated companies and is intended to:

- minimize the potential for a utility to cross-subsidize competitive or non-monopoly activities;
- protect the confidentiality of consumer information collected in the course of providing utility services; and
- ensure there is no preferential access to regulated utility services.

The Code specifically sets out standards of conduct including the degree of separation, sharing of services and resources, terms under which service agreements must be prepared and transfer pricing guidelines.

CHANGES IN ACCOUNTING POLICIES

United States Generally Accepted Accounting Principles
The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Company is permitted to prepare its consolidated financial statements in accordance with U.S. GAAP for purposes of meeting its Canadian continuous disclosure requirements under an exemption granted by securities regulators in Canada.

ADOPTION OF NEW STANDARDS
Balance Sheet Offsetting
Effective January 1, 2013, the Company adopted Accounting Standards Update (ASU) 2011-11 and ASU 2013-01, which require enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. As the adoption of these updates impacted disclosure only, there was no impact to the Company's consolidated financial position for the current or prior periods presented.

Accumulated Other Comprehensive Income
Effective January 1, 2013, the Company adopted ASU 2013-02, which requires enhanced disclosures on amounts reclassified out of AOCI. As the adoption of this update impacted disclosure only, there was no impact to the Company's consolidated financial statements for the current or prior periods presented.

Presentation of Unrecognized Tax Benefits
Effective December 31, 2013, the Company elected to early adopt ASU 2013-11 which requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of this update.

FUTURE ACCOUNTING POLICY CHANGES
Obligations Resulting from Joint and Several Liability Arrangements
ASU 2013-04 was issued in February 2013 and provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively.

Parent's Accounting for the Cumulative Translation Adjustment
ASU 2013-05 was issued in March 2013 and provides guidance on the timing of release of the cumulative translation adjustment into earnings when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied prospectively.

ENBRIDGE GAS DISTRIBUTION INC.
HIGHLIGHTS

Year ended December 31,	**2013**	2012
Financial *(millions of Canadian dollars)*		
Gas commodity and distribution revenue	**2,221**	1,869
Transportation of gas for customers	**328**	345
Other revenue	**99**	202
Total revenue from continuing operations	**2,648**	2,416
Gas commodity and distribution costs excluding depreciation	**(1,480)**	(1,229)
	1,168	1,187
Earnings from continuing operations	**217**	208
Earnings from discontinued operations	**-**	4
Earnings	**217**	212
Earnings attributable to the common shareholder	**215**	210
Return on equity[1] (%)	**9.0**	9.2
Operating		
Volumetric statistics *(millions of cubic metres)*		
Gas commodity sales	**7,365**	6,171
Transportation of gas for customers	**4,553**	4,572
Unbundled volumes[2]	**378**	444
Total volume	**12,296**	11,187
Number of active customers[3] *(thousands)*	**2,065**	2,032
Heating degree days[4]		
Actual	**3,746**	3,194
Forecast based on normal weather	**3,668**	3,532

1. *Return on equity data relates to the consolidated entity.*
2. *Unbundled customers deliver their own natural gas into the Company's distribution system and manage their load balancing independent of the Company.*
3. *Number of active customers is the number of natural gas consuming customers at the end of the year.*
4. *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area. It is calculated by accumulating, for the fiscal year, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. A daily mean temperature of zero degrees Celsius on any day equals 18 heating degree days for that day. The figures given are those accumulated in the GTA.*

UNDERTAKING J1.3

UNDERTAKING

TR 27

To show impact of accounting errors on financial results.

RESPONSE

Please see tables provided below:

TABLE -1: As filed in Exhibit I.A10.EGDI.CCC.12

Line No		2008 Historical	2009 Historical	2010 Historical	2011 Historical	2012 Historical	Total
1.	Allowed ROE (without 100bp ESM allowance)	8.66%	8.31%	8.37%	7.94%	7.52%	
2.	Actual ROE Before Earnings Sharing	11.87%	12.36%	10.25% (2)	10.43% (2)	7.62% (2)	
3.	Actual Normalized ROE Before Earnings Sharing	10.21%	11.20%	11.10% (2)	10.38% (2)	9.28% (2)	
4.	Gross Normalized Overearnings ($millions) (Note 1)	31.7	59.0	54.7	48.4	34.4	228.2
5.	Shareholders' Share of Gross Overearnings ($millions) (Note 1)	26.1	39.7	37.4	34.1	27.0	164.3
6.	Ratepayers' Share of Gross Overearnings ($millions)	5.6	19.3	17.4	14.3	7.4	64.0
7.	Actual Normalized ROE /After Earnings Sharing	9.94%	10.26%	10.24% (2)	9.66% (2)	8.90% (2)	

Note 1: Amounts include impact of 100bp allowed for earnings sharing purposes during the 2008-2012 incentive term, additionally, these are not true resulting net earnings amounts as they include tax amounts payable.

Note 2: These are the previously reported actual and normalized ROE%'s which have not taken into account the impact of the accounting error identified within EGDI's September 30, 2013 Financial Results.

TABLE -1: Updated to reflect the accounting error impacts

Line No		2008 Historical	2009 Historical	2010 Historical	2011 Historical	2012 Historical	Total
1.	Allowed ROE (without 100bp ESM allowance)	8.66%	8.31%	8.37%	7.94%	7.52%	
2.	Actual ROE Before Earnings Sharing	11.87%	12.36%	9.26%	8.97%	6.06%	
3.	Actual Normalized ROE Before Earnings Sharing	10.21%	11.20%	10.07%	8.91%	7.63%	
4.	Gross Normalized Overearnings ($millions) (Note 1)	31.7	59.0	34.1	19.3	2.1	146.2
5.	Shareholders' Share of Gross Overearnings ($millions) (Note 1)	26.1	39.7	16.7	5.0	(5.3)	82.2
6.	Ratepayers' Share of Gross Overearnings ($millions)	5.6	19.3	17.4	14.3	7.4	64.0
7.	Actual Normalized ROE /After Earnings Sharing	9.94%	10.26%	9.21%	8.18%	7.25%	

Note 1: Amounts include impact of 100bp allowed for earnings sharing purposes during the 2008-2012 incentive term, additionally, these are not true resulting net earnings amounts as they include tax amounts payable.

Witness: K. Culbert

UNDERTAKING J1.4

UNDERTAKING

TR 1

To provide Enbridge Gas Distribution’s Strategic Plan.

RESPONSE

Please see Attachment 1- Enbridge Gas Distribution’s Strategic Plan.

Witness: K. Culbert

ENBRIDGE

Gas Distribution
2013 Strategic Plan

Confidential

May 29, 2013

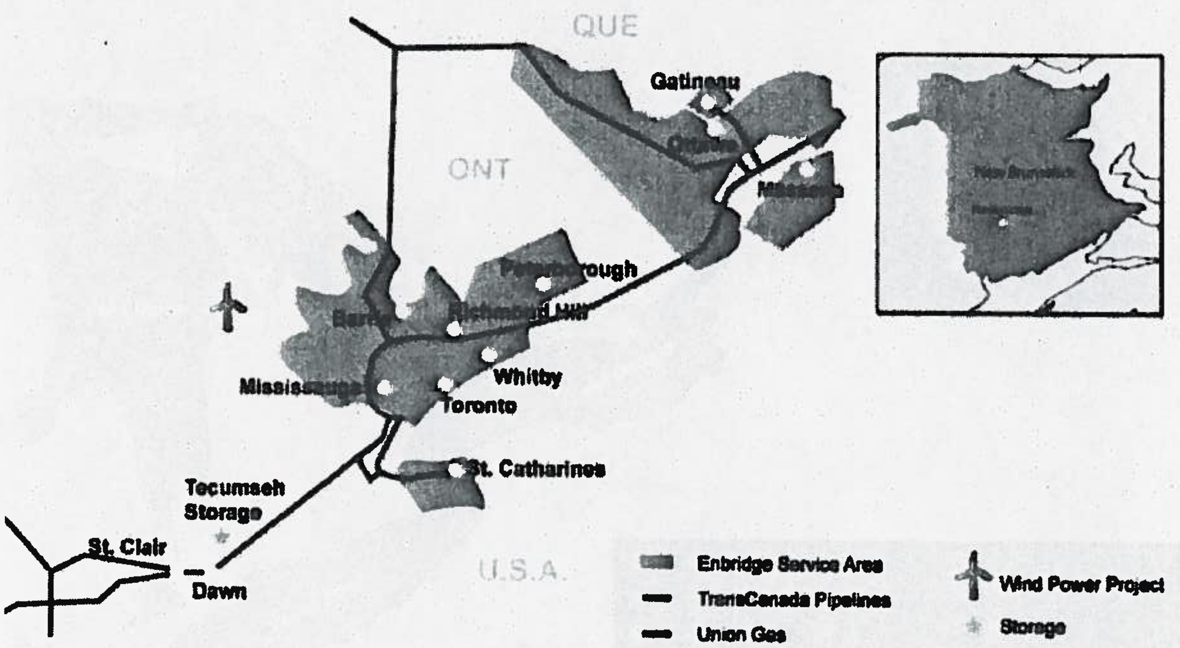
GAS DISTRIBUTION

For the purpose of this document, Gas Distribution (GD) refers to the Gas Distribution business unit of Enbridge Inc. and includes Enbridge Gas Distribution (EGD or the Company), Enbridge St. Lawrence Gas (ESLG), Gazifère, Enbridge Gas New Brunswick (EGNB) and other unregulated businesses.

BUSINESS UNIT SUMMARY

GD serves residential, commercial and industrial customers in central and eastern Ontario, Quebec, several communities in New Brunswick and areas in northern New York State.

GAS DISTRIBUTION FRANCHISE AREA



EGD currently serves over 2 million residential, commercial and industrial customers and remains one of the fastest growing natural gas distribution companies in North America. In 2012, EGD added about 36,000 new customers. Residential customers comprise approximately 92% of the total customer base, and consume approximately 51% of total throughput. Due to mild temperatures in 2012, the Company distributed 389 billion cubic feet (Bcf) of natural gas, below historic norms of approximately 420 Bcf. The Company also owns 110 Bcf of underground storage capacity.

Overview of Current Environment and Fundamentals

Economic Fundamentals

Ontario's 2013 economic outlook sees a continued trend of moderate growth, according to consensus among government and financial institutions. On par with real GDP growth of 2.0% in 2012, the province's economy is forecasted to grow by 1.9% in 2013, transitioning to above 3% by 2017. This period encompasses EGD's Long Range Plan (LRP) as well as most of the next generation Incentive Regulation (IR) regime set to begin in 2014.

Detailed below are key economic indicators relevant to the GD business:

Manufacturing and Industrial Sector Performance

The Canadian dollar appreciated to a high of 103.3 cents US in 2012. Private-sector forecasters expect the dollar to remain close to parity throughout 2013 and into the medium term as commodity prices remain firm. The strong dollar, coupled with lingering uncertainty surrounding US government spending cuts and resultant fiscal drag, will not bode well for Ontario's export-heavy manufacturing and industrial sectors in early 2013. In the latter part of 2013 and into the medium term, exports will once again drive industrial and manufacturing growth. Overall industry GDP growth is expected to slow to 1.7% in 2013, from 2.1% in 2012.

The Ontario power generation sector represents a potential growth story for natural gas in the medium term. The province is becoming capacity constrained; it is in the final stages of shutting down its residual coal-fired-capacity by 2014. While additional nuclear units at the Darlington station are being discussed, natural gas generating stations have the advantage of shorter lead times. The Conference Board of Canada forecasts natural gas generation capacity additions of 1,743 MW from 2012 – 2015, and 1,900 MW from 2015 – 2020.

Housing Market

The Ontario housing market was particularly strong in the first quarter of 2012, supported by solid underlying demand and record-low mortgage rates. Housing indicators through the fall and winter have pointed to a cooling in the market. Demand is expected to moderate further in 2013 and 2014 due to recent changes to mortgage rules, as the Federal Government attempts to rein in household debt and mitigate the potential for a housing bubble

Falling below a seven-year high of 77,000 units in 2012, housing starts are projected to decline by approximately 10% to 70,000 units in 2013, and remain at that level until 2015 . Apartment and condominium share of provincial housing starts increased from below 40% last decade to above 60% in 2012.

Below are GD's historical and projected customer additions. Customer additions derived from new construction continue to be the cornerstone of growth, yet remain relatively flat from 2013 onward. This forecast parallels CMHC housing start projections for the same period.

Franchise Area Customer Adds *	2010	2011	2012	2013F	2014F	2015F
New Construction	29,878	27,293	27,191	31,290	28,636	30,728
Replacement	7,024	8,364	8,780	7,289	8,011	7,761
Total	36,902	35,657	35,971	38,579	36,647	38,489

** Projections sourced from EGD's 2013 LRP*

Interest Rates and Bond Yields

Government of Canada 10 and 30-year bond yields are embedded in EGD's allowed-ROE calculation, playing an integral role within the Earnings Sharing Mechanism (ESM) of the previous IR regime that ended in 2012; GD benefitted from low interest rates during the last IR term, generating incremental earnings from the gap between actual and forecasted rates which were established in the IR model that was developed pre-recession. Bond yields were included in the calculation to act as a benchmark against which GD's ROE is measured relative to similar low-risk investment vehicles - a means of controlling earnings by sharing productivity enhancements with ratepayers.

However, low Government of Canada bond yields of late have lowered GD's allowed-ROE, dropping steadily from 8.4% in 2007 to 7.5% in 2012. A new ROE formula approved and adopted for 2013 resulted in a rate of 8.93%.

Natural Gas Prices

Despite forecast increases in natural gas prices over the planning horizon, natural gas is expected to retain its significant price advantage versus oil and electricity over the short and long term. The expected price advantage for natural gas is largely driven by the North American supply picture. Increased production of shale gas is expected to keep natural gas prices cheaper relative to oil and electricity. The table below demonstrates the savings from using natural gas versus oil and electricity for GD's typical residential, commercial and industrial customers.

Natural Gas Advantage Annual Cost Savings based on Typical Bill

		2012	2013*
Residential	Home Heating Oil	69%	73%
	Electricity	70%	69%
Commercial	Light Fuel Oil	69%	66%
	Electricity	77%	75%
Industrial	Light Fuel Oil	79%	75%
	Electricity	79%	76%

** 2013 savings are based on rates effective Jan 2013*

Legislation & Public Policy

The political climate in Ontario continues to present challenges stemming from a lack of stability and ongoing political volatility. The provincial Liberal Government is in a minority parliament, has seen the resignation of Premier McGuinty after nine years, electing Kathleen Wynne as their new leader and Ontario is faced with strong probability of an election before year end.

This period of instability and the potential for change in political leadership underscores the need for continued execution of a multi-pronged government relations strategy that creates the conditions to enable the government and/or opposition parties to view natural gas as a "fuel of choice". Much of the dialogue surrounding natural gas in Ontario has focused on the government's controversial cancellation of two natural gas plants in Oakville and Mississauga and strategic efforts are being made to steer the conversation towards the advantages of the fuel. Enbridge Gas has recently partnered with Union Gas to launch joint advocacy efforts to raise the natural gas profile through the formation of the Ontario Natural Gas Alliance (ONGA).

As the provincial government continues to review its workplace injury prevention policies, efforts are underway to position Enbridge as a safety leader by highlighting our safety initiatives and investments and continuing to engage with government to support this process.

Regulatory Environment

In 2013, EGD is operating in a Cost of Service regulatory framework. As part of the 1st Generation Incentive Plan, which functioned over the 2008-2012 period, EGD agreed to rebase its costs for 2013. The rebasing was intended to refresh EGD's costs, revenues, and cost of capital values and provide stakeholders with the benefits of productivity and efficiency gains achieved during the Incentive Regulation (IR) period. The Cost of Service application was filed in early 2012 and resulted in a significant settlement agreement produced in the fall of 2012. Key features of the Settlement Agreement include:

- 2013 O&M Budget of $415
- Adoption of a new ROE formula resulting in a 2013 allowed-ROE of 8.93%
- 2013 Capital Budget of $387 million

The main issue that was not settled as part of the 2013 application was a request for an increase in the equity ratio from 36% to 42%. The OEB issued its decision on February 7, 2013 denying the Company's request for the increase in the equity ratio. The regulatory team at EGD will investigate if it would be appropriate to pursue this issue further through a generic proceeding or through a Cost of Capital Review proceeding that the Board is expected to conduct in 2014.

The Cost of Service framework established for 2013 will also serve as the base or starting point for the 2nd Generation IR plan. Positive stakeholder relationships fostered as a result of the 2013 settlement process should provide a strong starting point for negotiations on the 2014 IR plan

STRATEGIC PRIORITIES

Incentive Regulation

Strategic Opportunities/Issues

EGD is planning to file its 2nd Generation Incentive Regulation (IR) Plan with the OEB in June, 2013.

The 2nd Generation IR Plan proposes a number of changes from the 1st Generation Plan. EGD designed its 2nd Generation IR Plan using a "custom model" approach which will cover the period from 2014 to 2016 and is structured to respond to forecast business needs which include significant increased capital investments for safety, system integrity and reliability initiatives. This is in contrast to the 1st Generation IR Plan which relied on an "inflation minus productivity" escalation factor for annual rate setting. The proposed IR Plan will provide EGD the opportunity to earn its allowed return and preserves incentives for the Company to earn above its allowed return.

EGD is planning to increase its capital investment program over the next 3 years as result of numerous Operational Risk Management (ORM) initiatives, the GTA and Ottawa Reinforcement projects and the need for a renewed Work and Asset Management System. EGD's total capital expenditures over the IR term are forecast to be $2.1 billion, which represents a 60% increase over the total capital spent during the previous three years.

This significant increase in capital spending translates directly into a higher rate base and annual depreciation expense, which in turn results in an annual revenue requirement that is much higher than what a traditional "inflation minus productivity" inflator methodology would provide.

In addition, given that there is uncertainty around the outcome of a number of important integrity studies currently underway and their impact on capital spending requirements beyond 2016, EGD concluded that it is appropriate to pursue a three year term versus the five year term of the 1st Generation IR Plan. The new Plan will also include the tracking of productivity initiatives and operational performance, which is now a mandatory requirement for all electric utilities in Ontario.

Strategic Response – IR Application Approach

At a high level, the elements of the proposed 2nd Generation IR plan will include:

1. The 2nd Generation IR Plan establishes the annual allowed revenue for each year of the term based on a "bottom up" forecast of O&M and capital costs, depreciation, debt interest rates, tax rates and ROE. Therefore, aside from the GTA Reinforcement Project where a true-up mechanism is being proposed, the Company will be at risk for any overspending in these areas during the term.

2. An equity to debt ratio of 36/64 will be locked-in for the term, as would the forecast return on equity based on the OEB's existing ROE methodology.

3. A reduction in annual site restoration depreciation expense to approximately $30 million from the current $56 million, and a reduction in the existing reserve balance to $600 million over the next five years from the current $894 million. These new levels will be sufficient to meet the future needs of the business and will buffer the rate increases that would otherwise have occurred.

4. The Plan will include a proposed mechanism for earnings sharing that is identical to the sharing mechanism adopted in the 1st Generation IR along with an "off-ramp" having a symmetrical 300 basis point collar around the annual allowed ROE.

Implementation Progress to Date

EGD is targeting a late Q2 filing for the second-generation IR proposal to the OEB. Although precise timelines are not yet known, it is expected that a settlement conference and hearing (if required) will likely convene in the fall. A decision is expected in the first quarter of 2014.

"Simply the Best"

Strategic Opportunities/Issues

EGD's 2012 Strategic Planning process included a comprehensive employee engagement and consultation exercise to identify the key gaps in the Company's strategy to become the "Best North American Utility" across a number of dimensions. The goal of this exercise was to position EGD for success during the next IR period, by focusing on excellence in all aspects of our business.

The outcome of this consultation activity was a portfolio of strategic execution priorities, subsequently branded "Simply the Best." These strategic priorities are centred on the following four focus areas:

1. Best People
2. Best Customer Experience
3. Best Partnerships
4. Best Work Practices (including Operational Risk Management)

Strategic Response

Each of these four focus areas contains a number of initiatives which have been fully documented, planned and resourced for 2013, with the objective of making progress towards the goal of becoming the Best North American Utility.

Best People Initiatives: GD's employee growth during the planning period is expected to remain largely consistent with past experience, about 1% per year. Although significant employee growth is not expected as in other business units, the Simply the Best framework will bring focus to improving and enhancing existing people-related processes: leadership development, performance management, recruitment strategy, succession planning, workload planning, and span of control issues.

Best Customer Experience Initiatives: EGD will strive to be recognized as our customers as the best provider of utility services in North America. Initiatives are underway to achieve this goal through improvements in customer inquiry, billing, customer communications and self-serve options.

Best Partnerships Initiatives: EGD's highly leveraged service delivery model requires a clearly defined and consistent resourcing or partnership strategy. EGD is approaching this goal with a thorough examination and evaluation of immediate resourcing priorities in the short term, and a more strategic analysis of what we outsource and how we outsource in the longer term. Ultimately, this analysis will inform our partnership execution strategy.

Best Work Practices Initiatives: EGD has identified a number of priority work practices that require attention to improve safety, productivity and operational excellence. These include Operational Risk Management; Process Prioritization; Customer Connections Commitments; Asset Management Excellence; Capital Management; Workload Planning; and, Work and Asset Management.

Implementation Progress to Date

The Simply the Best efforts commenced in the first quarter of 2013; work stream owners have begun reporting progress on a monthly basis. A formal governance model is in place, including internal communications and change management disciplines, to ensure clarity and focus on initiatives, and to maximize employee engagement and participation. Although a series of initiatives are underway in 2013 to position EGD for future success, the long run objective of Simply the Best is not to change what EGD does, but rather how day- to-day business is carried out.

Operational Risk Management (ORM)

Strategic Opportunities/Issues

GD continues to focus on public and worker safety, and system reliability. Recent major energy related incidents across the industry have underscored the realities of public, environmental and reputational consequences, with regulators and the public further scrutinizing pipeline operational safety. To protect the company's "social license" to operate, new imperatives have resulted internally and from the industry at large. For GD, this includes the need to aggressively minimize the operational risks associated with the release of natural gas. By doing this, GD aspires to achieve:

- Zero Fatalities or Injuries
- Zero Third-Party Damages
- Zero Leaks and Ruptures

Strategic Response

Risk reduction is being achieved through ORM, which includes the execution of various projects and programs within six dimensions of Integrity, Engineering and Operations. These dimensions as well as the outcomes that risk reduction efforts are striving towards are summarized below:

Dimension	Outcomes
1) Integrity Management	Obtain and maintain accurate information of pipelines and other assets (e.g. location, condition, performance).
2) Leak Management	Find leaks before the public, and fix leaks as they are found.
3) Damage Prevention	Reduce third-party damages and increase safe digging awareness.
4) Incident Response	Maintain improved response times and improve ability to dispatch appropriate skill sets to incidents.
5) Worker Safety	Achieve "interdependent" position on the Dupont Bradley Curve, a mature safety culture with open communication and where individuals demonstrate care for others.
6) Public Safety	Improve public understanding of natural gas safety and end-use obligations.

Risk reduction efforts are designed to heighten GD's capability to prevent, detect and respond to risks associated with the release of natural gas. To manage the various aspects of ORM – strategy, risk, budget, execution, change management and communications – a Governance Support Team is in place at GD. The specific plans and programs are executed by teams in the Pipeline Integrity & Engineering and Operations groups. Achievements and lessons learned are shared amongst Business Units at the Operations and Integrity Committee meetings. Year-end results are reported to the Enbridge Board of Directors.

Implementation Progress to Date

In 2012, GD reduced operational risk in all six dimensions from 2011 levels

Gas Supply Strategy

Strategic Opportunities/Issues

EGD's gas supply strategy is based on the principles of reliability, flexibility, diversity, and cost.

EGD has almost doubled its customer base in the last 20 years and continues to be among the fastest growing gas LDC's in North America. The addition of predominantly temperature sensitive load and base load demand declines have resulted in higher peak day demand growth relative to average day demand creating a "peakier" system. These trends are expected to continue raising the need for additional supply flexibility and enhanced transportation and balancing services.

From a supply perspective, EGD continues to be concerned about reliability of supply associated with Direct Purchase volumes, peaking service, and curtailment - all of which are considered unsecured supply. Approximately 20% of Direct Purchase (DP) volumes (i.e. supplies provided by third parties directly into the franchise area) are underpinned by firm transport. Peaking services are increasingly being delivered through lower priority services, thus decreasing reliability of supply. Over the past few years, there have been several instances of interruptible customers failing to cease consumption when issued a curtailment notice or not delivering their full volumes or both. On a typical peak day approximately 15% of supply is not underpinned by firm transportation contracts.

Western Canadian Sedimentary Basin (WCSB) production is projected to continue to decline due to low prices and the inability to compete with less expensive US supplies. In addition, changes being contemplated on the TCPL Mainline such as conversion to oil and lower deliverability of pipe infrastructure due to suspension of integrity digs, could further reduce the quality of discretionary and less secure forms of transport on the Mainline.

Marcellus and Utica shale will change the North American pipeline grid from both a flow and pricing perspective. However, new pipeline infrastructure will be needed to support projected production. This new supply is physically located close to the EGD market area and has the potential to stabilize natural gas prices at moderate to low levels despite growing demand for natural gas.

Strategic Response

EGD will implement a transitioned approach for its supply portfolio in order to limit risks associated with basin performance, TCPL tolls, new infrastructure builds and regulatory considerations. The strategies outlined below will be employed by EGD to bring about changes in the supply portfolio:

1. Increase the use of short-haul transportation to firm-up peaking and reduce non-renewable Short Term Firm Transportation (STFT).
2. Firm up DP Deliveries.
3. Diversify to new supply basins and new transportation hubs.
4. Shift from Long Haul transportation and WCSB production to Short Haul transportation.
5. Greater Toronto Area (GTA) reinforcement project to address system flexibility, security of supply and meet incremental market demand

Implementation Progress to Date

The table below provides a summary of the key strategies and contemplated timing for execution:

	Immediate 2012/13	Near Term 2014/15	Long Term 2016+
Peaking and STFT	• Niagara supply • Hold peaking	• Displace STFT and peaking with Dawn & Niagara supply	• Incremental short haul to meet growth
Direct Purchase	• Monitor supply • Initiate consultations on delivery point flexibility	• Finalize changes to policy post GTA Project in service	• Ensure policy changes are sustainable with changing supply and customer migration
Diversification of Short Haul	• Vector renewals • NEXUS • Niagara • Alliance	• Assess TCPL tolls • Monitor WCSB prospects	• Evaluate Iroquois and other short haul options in light of NEXUS/Niagara/Dawn shares
Displacement of WCSB long haul base load	• N/A	• Participate in TCPL regulatory process	• Assess optimal level of reliance on WCSB
GTA Project	• File LTC application • Work with upstream business partners to optimize infrastructure benefits • Work though regulatory approval process	• Plan for and begin construction • Project in service	• N/A

By following the strategies outlined above it is expected that reliance on unsecured sources of supply will be reduced, thereby increasing security of supply. Peaking supplies are expected to decline as is the reliance on STFT while firm short haul transportation from Niagara and Dawn will increase. Additional diversity will be added by accessing emerging sources of supply delivered, or directly accessed, via Niagara which also improves security of supply through displacement of discretionary services on the Mainline. The amount of long haul capacity in the supply portfolio and the potential for displacement of this capacity will continue to be evaluated as the market evolves.

Utility Growth

Strategic Opportunities/Issues

Currently, with the significant price advantage of natural gas over alternative fuels in Ontario there exists a tremendous opportunity for EGD to accelerate customer additions through conversion of non-customers along existing mains, system expansion and short main extensions. A typical residential customer has the potential to save up to $2,800 on their annual energy bill by converting from oil, and $2,200 by converting from electricity This level of potential bill savings has not been seen in over 20 years in Ontario, and the relative price advantage is expected to remain the same or increase in the medium term.

Typically EGD adds about 6,000-9,000 replacement customers (customers who have converted from an alternative fuel) per year, although that number is on a downward trend as saturation of the potential replacement market increases over time. The balance (and majority) of customer additions are from new construction, but these numbers have also declined recently due to poor economic conditions and a weak builder market. EGD has a very limited ability to influence the builder market, but we can influence conversions through marketing and sales efforts.

Strategic Response

Potential areas of additional customer growth are being identified using the Company's Geographic Information System (GIS) and postal code data from publically available sources. These searches will identify communities with high concentrations of residential and business customers as candidates for system expansion. To date, 5-10 communities and a number of smaller projects have been identified as high potential opportunities. Estimated capital investment required to service this expansion will be approximately $250 million over five years.

A pro-active municipal government relations strategy will be developed to influence local governments and other stakeholders to support expansion initiatives, and to identify community-specific funding opportunities.

FINANCIAL FORECAST

Earnings Forecast

GD earnings over the 5-year planning horizon increase from $[redacted] million in 2013 to $[redacted] million in 2017, representing an annual compound growth rate of [redacted]%. The breakdown of earnings by company is set out in the figure below.

The increase in earnings stems primarily from EGD rate base growth and the allowed-ROE uplift approved by the OEB for 2013. Ratebase is forecast to rise from $4.2 billion in 2013 to $5.9 billion by 2017 as a result of continued customer growth and system reinforcement projects, notably GTA and Ottawa; while allowed-ROE is forecast to increase from 8.93% in 2013 to 10.17% in 2017.

$ Millions	Actual 2012	Forecast 2013	LRP 2014	LRP 2015	LRP 2016	LRP 2017	Sum of 2013-17
EGD – Corporate[1]	149	131	139	158	194	206	828
GD Stretch		27	15	19	19	6	86
EGNB	[redacted]						
Gazifère							
St. Lawrence							
Niagara							
Unreg. Storage							
Sub-Total							
Total GD Earnings	[redacted]						
YoY Δ ($)		[redacted]					
YoY Δ (%)							

[1] EGD assumes 36% equity thickness and weather normalized net of PPD

Capital Investment Program

Capital investments included in the 2013 LRP support the GD growth and sustainable operations strategy. The figure below details the capital expenditure program.

From 2013 to 2017, GD plans to invest [redacted] billion, of which $3.2 billion is related to EGD. This level of capital expenditures supports GD's commitment to ORM, GTA and Ottawa reinforcement projects, organic growth, maintenance and replacement of aging infrastructure, and upgrades to safety and security of supply.

($ Millions)	Actual 2012	Fcst 2013	LRP 2014	LRP 2015	LRP 2016	LRP 2017	Sum of 2013-17
Customer Related Capital	102	96	91	97	102	105	491
System Improvements/Upgrades	91	141	181	180	176	194	871
Overheads	113	115	119	118	120	123	594
IT Capital	39	26	29	27	28	32	142
General Plant	25	18	30	29	24	22	123
Underground Storage Plant	19	22	18	11	9	10	69
Maintenance Capital	423	418	469	462	458	485	2,291
Y Factors/Power Generation	3	-	9	-	2	-	11
Community Expansion	-	-	-	-	-	50	50
Ottawa Reinforcement	1	44	5	-	-	-	49
GTA Reinforcement	8	19	205	394	-	-	619
WAMS	-	7	37	26	8	-	78
Special Utility Projects	12	70	256	420	10	50	806
Total Utility Capital	435	488	725	882	468	535	3,097
Oil and gas	-	1	2	4	0	0	7
Net Cost of Retirements (CI)[1]	14	4	-	-	-	-	4
Net Cost of Retirements (non-CI)[1]	13	17	16	17	16	14	80
Net EGD Capex Total[2]	462	509	743	902	484	549	3,188
<u>GD Affiliates</u>							
Enbridge Gas New Brunswick	[redacted]						
Gazifere							
St. Lawrence							
Niagara Gas							
Unregulated Gas Storage							
Total GD Capital							

[1] CI denotes: Cast Iron
[2] EGD capital excludes VPC Building replacement; Community expansion excluded from ratebase in base case analysis

UNDERTAKING J1.8

UNDERTAKING

TR 145

To confirm whether numbers on slide 5 of TC1.5 are NPV numbers; if not, explain what the chart is showing numerically.

RESPONSE

The numbers in rows A to D of slide 5 are intended to represent the annual present value of benefits (in 2019 dollars) from four hypothetical initiatives undertaken during the IR term. The totals are the net present value (NPV) of benefits for each initiative.

The present value of benefits amount for any particular initiative in any particular year is intended to represent the discounted present value of benefits forecast from the initiative in that year (in 2019 dollars), less the forecast costs associated with the initiative to be expended during that year. In the result, the hypothetical examples show that the present value of the benefit is negative in the first year(s) of an initiative, while the initial expenses are being incurred, and the present value of the benefit becomes positive as the initiative matures.

Witness: R. Fischer

UNDERTAKING J1.9

UNDERTAKING

TR 154

Explain the changes in the 2014 System Integrity number that has been updated within the chart following paragraph 4 at Exhibit A2, Tab 1, Schedule 3.

RESPONSE

This is a correction to match Exhibit B2, Tab 1, Schedule 1 (Page 4). As seen in that exhibit, the categories of forecast 2014 capital expenditures are the following:

Cost categories	**$ Millions**
Customer Related	122
System integrity	243
Others	115
GTA & Ottawa	202
Total Capital Expenditure	682

Witness: M. Lister

UNDERTAKING J1.10

UNDERTAKING

TR 157

To provide clarification of the changes that were included within Enbridge's February 18, 2014 updated evidence.

RESPONSE

Please see the attached correspondence.

Witness: R. Fischer

Lorraine Chiasson

Subject: FW: EB-2012-0459 2014-2018 Rate Application - Updated Exhibits

From: Bonnie Adams
Sent: Wednesday, February 19, 2014 09:22 AM
To: Julie Girvan <jgirvan@uniserve.com>
Subject: RE: EB-2012-0459 2014-2018 Rate Application - Updated Exhibits

Good Morning,

The updated evidence filed yesterday is primarily directed at making modest corrections or updates to items that have already been filed. The main changes are:

- Addition of CVs for new witnesses
- A2-1-3, where the approach to removing SRC from the base (within Scenarios 4 to 6) has been changed to an approach where SRC is addressed solely through a Y-factor
- B2-1-1, where two tables are updated at the end of the evidence, to provide 2013 actual capital expenditures
- B2-3-1, where a line that should not have been part of Table 2 has been removed
- B2-9-1, where a calculation error in Table 2 has been corrected
- D1-3-1, where two tables are updated at the end of the evidence, to provide 2013 actual O&M expenses
- Updates/corrections to various IRs/Undertakings

Please contact me if you have any further questions.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

ENBRIDGE
TEL: 416-495-6409| CELL: 647-631-1439
500 Consumers Road, North York, ON M2J 1P8
www.enbridge.com

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From: Julie Girvan [mailto:jgirvan@uniserve.com]
Sent: Tuesday, February 18, 2014 9:15 PM
To: Bonnie Adams
Cc: boardsec@ontarioenergyboard.ca; colin.schuch@ontarioenergyboard.ca; kristi.sebalj@ontarioenergyboard.ca; laurie.klein@ontarioenergyboard.ca; brian_kelly@transcanada.com; carlton.mathias@opg.com; catharine_davis@transcanada.com; cconway@bomatoronto.org; colin.macdonald@powerstream.ca; david.butters@appro.org; DavidMacIntosh@nextcity.com; DR Quinn; fmurray@justenergy.com; ian.mondrow@gowlings.com; Shepherd Jay (jay.shepherd@canadianenergylawyers.com); jim_bartlett@transcanada.com; jsidlofsky@blg.com; jvellone@blg.com; jwolnik@elenchus.ca; kdullet@blg.com; laura-marie_berg@transalta.com; Lise Mauviel; Marion.Fraser@rogers.com; murray_ross@transcanada.com; nadine_berge@transcanada.com; nruzycki@justenergy.com; opgregaffairs@opg.com; pamelajones@hydroottawa.com; patrickhoey@hydroottawa.com; paul.clipsham@cme-mec.ca; pete_serafini@transalta.com; McMahon, Patrick; powerstreamregulatory@powerstream.ca; pthompson@blgcanada.com; randy.aiken@sympatico.ca; regulatoryaffairs@enersource.com;

regulatoryaffairs@hydroottawa.com; regulatoryaffairs@torontohydro.com; srahbar@igua.ca; tbrett@foglers.com; tce_regulatory@transcanada.com; tceast_marketaffairs@transcanada.com; tom.ladanyi@opg.com; transcanada_mainline@transcanada.com; vderose@blgcanada.com; vyoung@aegent.ca; wmcnally@opsba.org; jcoyne@ceadvisors.com; mbartos@ceadvisors.com; jsimpson@ceadvisors.com; julia@londoneconomics.com; Cherrylin Trinidad (cherrylin@londoneconomics.com); kelima@londoneconomics.com
Subject: Re: EB-2012-0459 2014-2018 Rate Application - Updated Exhibits

Bonnie - what would be helpful if for Enbridge to provide a brief summary of any significant changes reflected in these updates.

Thanks

Julie

Sent from my iPhone

On Feb 18, 2014, at 9:06 PM, Bonnie Adams <Bonnie.Adams@enbridge.com> wrote:

> Good Evening,
>
> Attached please find the recent submission of Enbridge Gas Distribution filed with the Ontario Energy Board (the " Board") for the above noted proceeding.
>
> The submission has been filed through the Board's Regulatory Electronic Submission System (RESS) and the confirmation number is 22773.
>
> Paper copies are being sent to the Board via courier.
>
> Please contact me if you have any questions.
>
> Sincerely,
>
> Bonnie Jean Adams
> Regulatory Coordinator
>
> ENBRIDGE
> TEL: 1-888-659-0685 (Toll Free) or 416-495-5499
> 500 Consumers Road, North York, ON M2J 1P8
> www.enbridge.com
>
> **Integrity. Safety. Respect**

<EGDI_UpdatedExhibits_20140218.pdf>

Lorraine Chiasson

Subject: FW: EB-2012-0459 2014-2018 Rate Application - Updated Exhibits
Attachments: A2-1-3 updated 20140218- Blacklined.pdf; TCU1.14 updated 20140218 Blacklined.pdf

From: Bonnie Adams
Sent: Wednesday, February 19, 2014 06:05 PM
To: Brett, Thomas <tbrett@foglers.com>
Subject: RE: EB-2012-0459 2014-2018 Rate Application - Updated Exhibits

Hello,

In response to your recent request, below please find a summary of the updated exhibits:

- Exhibit A1-Tab 6 - Schedule 5 - Addition of CVs for new witnesses
- A2-1-3, where the approach to removing SRC from the base (within Scenarios 4 to 6) has been changed to an approach where SRC is addressed solely through a Y-factor (see attached blackline – please note that changes to tables do not show up as blacklined)
- B2-1-1, where two tables are updated at the end of the evidence, to provide 2013 actual capital expenditures (New pages 44 and 45)
- B2-3-1, where a line that should not have been part of Table 2 has been removed (page 5)
- B2-9-1, where a calculation error in Table 2 has been corrected (page 3)
- D1-3-1, where two tables are updated at the end of the evidence, to provide 2013 actual O&M expenses (New pages 27 to 28)
- Updates/corrections to various IRs/Undertakings - please note that most of the changes are in charts, which do not show up in blacklines – a blackline of TCU1.14 is attached.

Please let me know if I can be of any further assistance.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

ENBRIDGE
TEL: 416-495-6409| CELL: 647-631-1439
500 Consumers Road, North York, ON M2J 1P8
www.enbridge.com

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From: Dey, Debbie [mailto:ddey@foglers.com] **On Behalf Of** Brett, Thomas
Sent: Wednesday, February 19, 2014 10:02 AM
To: Bonnie Adams
Subject: RE: EB-2012-0459 2014-2018 Rate Application - Updated Exhibits

Hello Bonnie,

Please send a blacklined version of the updated exhibits that were filed yesterday.

Thank you.

Tom Brett
Fogler, Rubinoff LLP
Lawyers
77 King Street West
Suite 3000, P.O. Box 95
TD Centre North Tower
Toronto, ON M5K 1G8
Direct: 416.941.8861
Main: 416.864.9700
Toll Free: 1.866.861.9700
Fax: 416.941.8852
Email: tbrett@foglers.com
foglers.com

From: Bonnie Adams [mailto:Bonnie.Adams@enbridge.com]
Sent: Tuesday, February 18, 2014 9:06 PM
To: boardsec@ontarioenergyboard.ca; colin.schuch@ontarioenergyboard.ca; kristi.sebalj@ontarioenergyboard.ca; laurie.klein@ontarioenergyboard.ca
Cc: brian_kelly@transcanada.com; carlton.mathias@opg.com; catharine_davis@transcanada.com; cconway@bomatoronto.org; colin.macdonald@powerstream.ca; david.butters@appro.org; DavidMacIntosh@nextcity.com; DR Quinn; fmurray@justenergy.com; ian.mondrow@gowlings.com; Shepherd Jay (jay.shepherd@canadianenergylawyers.com); jgirvan@uniserve.com; jim_bartlett@transcanada.com; jsidlofsky@blg.com; jvellone@blg.com; jwolnik@elenchus.ca; kdullet@blg.com; laura-marie_berg@transalta.com; Lise Mauviel; Marion.Fraser@rogers.com; murray_ross@transcanada.com; nadine_berge@transcanada.com; nruzycki@justenergy.com; opgregaffairs@opg.com; pamelajones@hydroottawa.com; patrickhoey@hydroottawa.com; paul.clipsham@cme-mec.ca; pete_serafini@transalta.com; McMahon, Patrick; powerstreamregulatory@powerstream.ca; pthompson@blgcanada.com; randy.aiken@sympatico.ca; regulatoryaffairs@enersource.com; regulatoryaffairs@hydroottawa.com; regulatoryaffairs@torontohydro.com; srahbar@igua.ca; Brett, Thomas; tce_regulatory@transcanada.com; tceast_marketaffairs@transcanada.com; tom.ladanyi@opg.com; transcanada_mainline@transcanada.com; vderose@blgcanada.com; vyoung@aegent.ca; wmcnally@opsba.org; jcoyne@ceadvisors.com; mbartos@ceadvisors.com; jsimpson@ceadvisors.com; julia@londoneconomics.com; Cherrylin Trinidad (cherrylin@londoneconomics.com); kelima@londoneconomics.com
Subject: EB-2012-0459 2014-2018 Rate Application - Updated Exhibits

Good Evening,

Attached please find the recent submission of Enbridge Gas Distribution filed with the Ontario Energy Board (the " Board") for the above noted proceeding.

The submission has been filed through the Board's Regulatory Electronic Submission System (RESS) and the confirmation number is 22773.

Paper copies are being sent to the Board via courier.

Please contact me if you have any questions.

Sincerely,

Bonnie Jean Adams
Regulatory Coordinator

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CHALLENGES OF AN I-X IR MODEL

Purpose of this Evidence

1. The purpose of this exhibit is to describe the challenges of an Inflation minus Productivity Factor ("I-X") formula based incentive regulation model for Enbridge Gas Distribution ("EGD" or "Company") in a 2nd Generation IR ("IR") term. This is accomplished through the development of a number of scenarios that determine ROE deficiency/sufficiencies assuming a revenue cap per customer I-X model versus forecast allowed ROE using the Company's filed budget O&M and capital forecasts. The development of "I" and "X" Factors is discussed in evidence provided by Concentric Energy Advisors, Inc. ("Concentric") at Exhibit A2, Tab 9, Schedule 1.

2. Specifically, this evidence will present:
   a) EGD System Challenges
   b) Traditional Model for Cost Recovery
   c) Limitations of I-X Frameworks
   d) Challenge of an I-X model in EGD's circumstances
   e) Challenge of Increasing Depreciation and Amortization Expense
   f) Other Considerations for a Customized IR

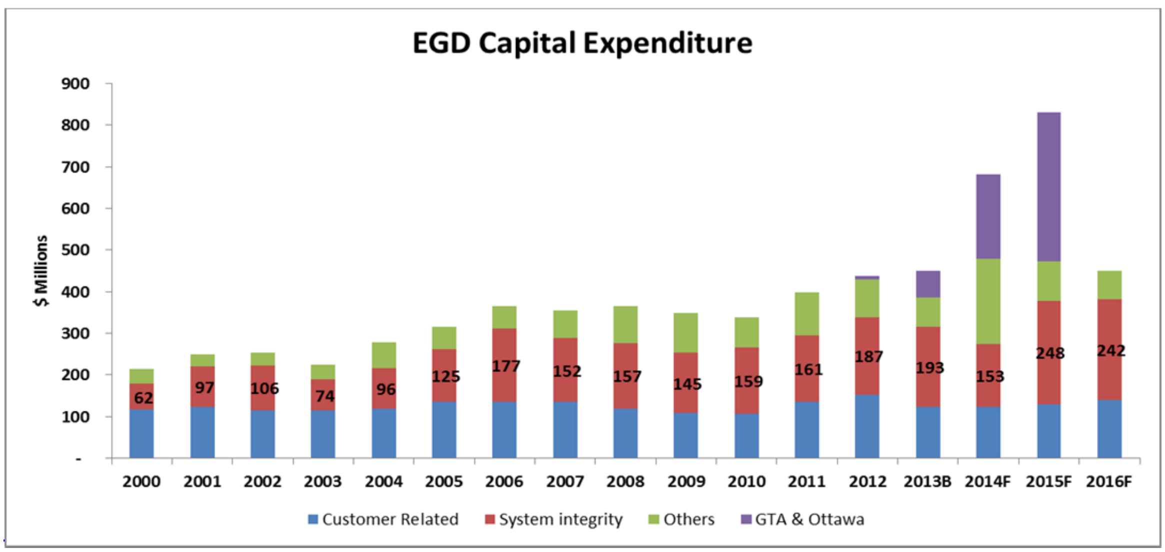
EGD System Challenges

3. EGD is one of North America's oldest investor owned, regulated natural gas distribution utilities and it shares many of the common challenges facing utilities across the globe – an increased focus on safety and reliability, aging assets and the need to cost effectively meet the demands of customer growth in its franchise area. In addition to these common challenges, Enbridge has one of the fastest growing customer bases in North America, which brings other cost challenges.

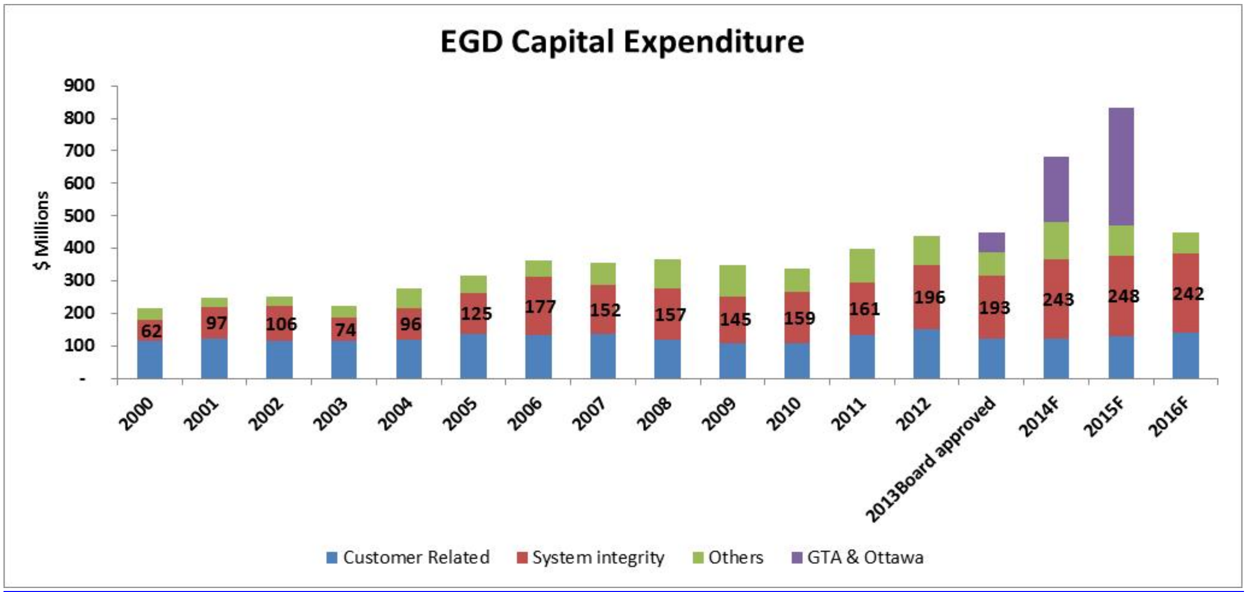
Witnesses: S. Kancharla
R. Fischer
M. Lister

Notwithstanding these characteristics, EGD remains committed to the safe, reliable operation of its gas distribution network and has made that commitment a business priority.

4. Over the last decade, EGD has experienced an increased need for system improvement and integrity related capital. As shown in the illustration below, the share of system integrity capital has been increasing historically and is expected to increase more significantly in the future.



Witnesses: S. Kancharla
R. Fischer
M. Lister



/u

5. EGD's Customized IR plan is structured to respond to these forecast business needs, which includes the expectation for significant increased capital investments for safety, system integrity and reliability initiatives driving the next 3 to 5 years. Specifically, EGD needs to increase its capital spending over the next 3 years to address unavoidable issues such as safety and integrity issues, relocations, IT projects, and the GTA and Ottawa Reinforcement projects. In fact, EGD's total capital expenditures over the next three years are forecast to be approximately $2.0 billion, which represents a 53% increase over the total capital spent during the previous three years.

6. This significant increase in capital spending translates directly into higher rate base and higher annual depreciation expense, which in turn results in an annual Allowed Revenue amount that is much higher than what a traditional Total Factor Productivity ("TFP") based "inflation less productivity" IR methodology would provide.

Witnesses: S. Kancharla
R. Fischer
M. Lister

7. The needs of the utility pose a challenge to EGD to develop an IR framework that accommodates the financial consequences associated with growing incremental capital. A traditional formula I-X based framework, with the X factor defined by reference to industry average TFP trends, was found to be insufficient to meet those needs because it clearly does not anticipate the unusual capital spending demands facing EGD. The traditional I-X approach will not provide EGD the capacity to fund its project capital investment needs and afford EGD a reasonable opportunity to earn the allowed return. As a result, the proposed Customized IR plan was developed.

8. EGD's 1st Generation IR model relied on an I-X escalator supplemented with a revenue cap per customer calculator and Y factors for specific incremental projects not subject to the revenue escalator. These "add-ons" to the traditional I-X model were designed to recognize the unique needs of the business during the term of the 1st Generation IR relating to funding customer growth and specific incremental projects not included in the 2007 base revenue requirement. These "add-ons" necessarily increased the complexity of the IR model. As the need for capital increases, additional "add-ons" in the form of new Y factors or other mechanisms such as capital trackers, would be required to increase the possibility that an I-X framework could work for EGD in the coming years. The inherent complexity of the 1st Generation IR framework would, as a result increase, further straining the applicability of a formula-based model for EGD's 2nd Generation IR term.

9. The scenarios evaluated below analyze whether an I-X model is still appropriate for EGD for its 2nd Generation IR term and also examine whether the creation of additional Y factors for EGD's two major reinforcement projects impoves the

prospects for EGD to earn its allowed return. The analysis also determines the results of a scenario where I-X is assumed to be held to the average I-X level that applied during the term of EGD 1st Generation IR and further assumes Y factors for the two major reinforcement projects.

Traditional Model for Cost Recovery

10. In a traditional Cost of Service ("COS") framework, all else being equal, rates are designed to result in neither a revenue sufficiency or deficiency, ensuring that all cost elements that contribute to the determination of revenue requirement are recovered. In turn, a COS framework generally provides a utility the ability to earn its allowed return. The utility's costs are reviewed closely before the regulator approves them for recovery through rates to ensure they are both prudent and just and reasonable expenditures.

11. Non-revenue generating capital investments, for example, replacements and certain reinforcements and relocations which ensure system reliability, cause upward pressure on rates as they do not promote customer attachment or result in increases in volume delivery. Traditional ratemaking frameworks such as COS allow for the recovery of prudent costs in rates, whereas in an I-X model, the percentage escalator must be sufficiently high to generate revenue increases to cover the costs of non-revenue generating capital investment without undermining a utility's reasonable opportunity to earn the allowed return.

Limitations of I-X Frameworks

12. Many utilities (and regulators) around the world have adopted multi-year Performance Based Ratemaking ("PBR") frameworks to overcome some of the perceived weaknesses of COS regulation by incorporating incentive mechanisms

and productivity in models that in turn encourage innovation and the realization of sustainable efficiencies. IR models are traditionally formula-based, starting from a COS rebasing year with revenue or rates escalated during the IR term through consideration of inflation and productivity factors in an I-X escalation formula. Multi-year IR plans encourage efficiencies and provide incentives for utilities to realize those efficiencies.

13. Under that form of IR, the utility is expected to manage its business within the confines of the I-X formula design. In this model, incremental capital expenditures produce an earnings drag since the utility is prevented under most circumstances from filing a COS rate case. This situation may be untenable in an environment where the growth rate in depreciation costs and other cost elements driven by capital investments more than outstrip the growth in revenue from the I-X formula. Further, finding efficiencies may be increasingly difficult, especially for a utility like EGD that can demonstrate a long history of strong relative productivity performance. In this case, the utility is forced to forego the return on and the return of the capital that is invested until there is a rebasing, which significantly impacts a utility's ability to earn a Fair Return, as defined by the Fair Return Standard.

14. For example, assume there is a $100 million increase in net capital above historic levels, driven by reinforcement and replacement projects. The incremental revenue required to provide cost recovery in a traditional COS model is approximately $8 million. This level of change from historical capital spending creates a condition where the normal rate of industry productivity improvement using I-X cannot reasonably compensate for the incremental costs. In addition, in subsequent years, there will be additive pressures to find more productivity enhancements as the foregone return on capital continues to accumulate. This situation creates a built-in

disincentive to invest in non-revenue generating projects. It is noteworthy that safety and integrity projects are, by their very nature, non-revenue generating projects.

Challenge of an I-X model in EGD's circumstances

15. In a traditional I-X IR framework, base rates are established in a rebasing year from an approved revenue requirement. At a high level, the approved revenue requirement includes operating cost and capital cost elements, including depreciation, return on capital and income tax. During an IR term, changes in revenue recovered through rates are capped by the application of an I-X adjustment factor (for a revenue cap).

16. In order to determine whether and how the Company could continue for a 2nd Generation IR term using a plan similar to the 1st Generation IR plan, Enbridge completed various financial analyses. The results of the analyses, which considered a variety of scenarios using an I-X framework, including additional Y factors for EGD's two major reinforcement projects, indicated that an alternative IR approach is required from that adopted for the 1st Generation IR term.

17. The analysis compared the expected ROE derived from an I-X framework versus the forecast allowed ROE using the Board's ROE formula to determine whether Enbridge could reasonably recover its capital investment and earn the Fair Return over the IR term.

Description of the analysis:

18. For each scenario, a revenue cap per customer calculator with an I-X revenue escalator was assumed and customer growth was forecast. The following factors

Witnesses: S. Kancharla
R. Fischer
M. Lister

were considered as Y factors (flow through costs) for each scenario - Carrying cost for Gas in storage; Pension Cost; DSM; and Customer Care. Forecast achieved ROEs were then compared to forecast allowed ROEs.

19. The following six scenarios were evaluated :

a) Scenario 1: No new Y factors for I-X model.
b) Scenario 2: Scenario 1 plus new Y factors for the GTA and Ottawa reinforcement projects.
c) Scenario 3: Breakeven escalation factor such that annual average ROEs in Scenario 2 are equal to forecast allowed ROE.
d) Scenario 4: Scenario 2 plus ~~reduction in depreciation expense and accumulated depreciation from reduction in Site Restoration Costs.~~SRC impact. /u
e) Scenario 5: Breakeven escalation factor such that annual average ROEs in Scenario 4 are equal to forecast allowed ROE.
f) Scenario 6: Same assumptions as Scenario 4 except I-X is assumed equal to the actual effective average I-X during the 1st Generation IR term.

Witnesses: S. Kancharla
R. Fischer
M. Lister

Key assumptions for the analysis:

20. For Scenarios 1 to 5, EGD assumed that the I-X escalator would equal 2.5%, based on an I factor forecast of 2.5% and a productivity factor or X factor of 0%. The I factor forecast represents the average composite inflation rate that applies to EGD's costs as recommended and forecast by Concentric at Exhibit A2, Tab 9, Schedule 1. The X factor is the recommended productivity factor derived from Concentric's TFP analysis in their report. For Scenario 6, EGD assumed an I-X = 0.9%.

21. These scenarios were evaluated for each of the next three years, assuming levels of capital and O&M spending that are consistent with Enbridge's forecast budgets included in this IR application (and which include embedded productivity).

22. The table below provides details of the other assumptions used in the analysis.

Assumptions

$ Millions	**2014**	**2015**	**2016**
Capital expenditure	682	832	450
Operating expenses	425	429	440
Customer growth	1.69%	1.73%	1.75%
Weighted Average Cost of debt (LT&ST)	5.41%	5.36%	5.31%
Allowed ROE	9.27%	9.72%	10.12%
Tax rate	26.50%	26.50%	26.50%
Inflation factor	2.45%	2.45%	2.45%
Productivity factor *	0.00%	0.00%	0.00%
Composite depreciation rate before SRC adjustment	4.03%	3.99%	3.94%
Composite depreciation rate with SRC adjustment	3.59%	3.55%	3.50%
Constant Dollar Net Salvage Value Adjustment	68.1	63.1	58.1

* Productivity savings are embedded within Enbridge's budgets

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and Interpretation of Scenario 1

23. Scenario 1 assumes no new Y factors for the GTA and Ottawa reinforcement projects. The 3 year average escalation factor is 2.5% and with customer growth, IR revenue is growing 4.2% per year. Layering on the existing Y factors results in average annual IR revenue growth of 3.5%. In this scenario, the achieved average annual ROE over the IR term would be 1.8% less than forecast allowed ROE.

Sc1: No new Y factors for I-X Model

	Rebase	Second Generation IR			
Revenue - IR ($M)	**2013**	**2014**	**2015**	**2016**	***3 yr - CAGR***
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	*2.5%*
Productivity		0.0%	0.0%	0.0%	
		2.5%	2.5%	2.5%	*2.5%*
Customer growth		1.7%	1.7%	1.7%	*1.7%*
		4.2%	4.2%	4.2%	*4.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**-**			
2013 Adjusted Revenue Requirement - Subject to escalation		**817**			
Revenue Requirement - IR with escalation	817	**851**	**887**	**925**	***4.2%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	-	-	-	
Site Restoration Cost - Tax impact	-	-	-	-	
	204	203	206	209	
Total Distribution Revenues -IR	**1,021**	**1,055**	**1,093**	**1,133**	***3.5%***
Achieved ROE	**8.9%**	**8.3%**	**8.7%**	**6.6%**	***7.9%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Acheived vs Allowed)	**0.0%**	**-1.0%**	**-1.0%**	**-3.5%**	**-1.8%**

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and Interpretation of Scenario 2

Sc2: Scenario 1 plus new Y factors for the GTA and Ottawa reinforcement projects

	Rebase	Second Generation IR			
Revenue Requirement - IR ($M)	**2013**	**2014**	**2015**	**2016**	***3 yr - CAGR***
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	*2.5%*
Productivity		0.0%	0.0%	0.0%	
		2.5%	2.5%	2.5%	*2.5%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		4.2%	4.2%	4.2%	*4.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**-**			
2013 Adjusted Revenue Requirement - Subject to escalation		**817**			
Revenue Requirement - IR with escalation	817	**851**	**887**	**925**	***4.2%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	64	
Site Restoration Cost - Tax impact	-	-	-	-	
	204	209	218	273	
Total Distribution Revenues -IR	**1,021**	**1,060**	**1,105**	**1,198**	***5.5%***
Achieved ROE	**8.9%**	**8.6%**	**9.2%**	**9.1%**	***9.0%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Acheived vs Allowed)	**-**	**-0.7%**	**-0.5%**	**-1.0%**	**-0.7%**

24. In this scenario, the major reinforcement projects in the GTA and Ottawa were considered as new Y factors in the I-X model. Layering on the existing Y factors and new Y factors for the two major reinforcement projects results in IR revenue growth of 5.5%. In this scenario, the achieved average annual ROE over the IR term under an I-X model would be 0.7% less than forecast allowed ROE.

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and interpretation of Scenario 3

Sc3: Breakeven escalation factor such that ROEs in Scenario 2 from I-X and allowed ROE are equal

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		4.3%	2.0%	4.0%	*3.4%*
Productivity		0.0%	0.0%	0.0%	
		4.3%	2.0%	4.0%	*3.4%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		6.0%	3.7%	5.9%	*5.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**-**			
2013 Adjusted Revenue Requirement - Subject to escalation		**817**			
Revenue Requirement - IR with escalation	817	**866**	**898**	**951**	***5.2%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	64	
Site Restoration Cost - Tax impact	-	-	-	-	
	204	209	218	273	
Total Distribution Revenues -IR	**1,021**	**1,075**	**1,116**	**1,224**	***6.2%***
Achieved ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Acheived vs Allowed)	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

25. In this scenario, the GTA and Ottawa reinforcement major projects were considered as new Y factors in the I-X model and an escalation factor is solved to produce ROEs from the I-X model equal to forecast allowed ROE. The 3 year I-X average escalation factor required in this case is 3.4%. This escalation factor is significantly

Witnesses: S. Kancharla
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greater than the 2.5% I-X derived from the productivity factor and inflation factors that are recommended and forecast by Concentric for an I-X IR model framework.

26. For the next two scenarios, the recommendations of the new depreciation study are incorporated. The key differences arise from the changes in “Site Restoration Costs” collected as part of depreciation expense and from the changes in “site restoration costs” accumulated and shown in “accumulated depreciation”. For details, please refer to Exhibit D1, Tab 5, Schedule 1.

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and interpretation of Scenario 4

Sc4: Scenario 2 plus reduction in depreciation expense and accumulated depreciation from reduction in Site Restoration costs

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	*2.5%*
Productivity		0.0%	0.0%	0.0%	
		2.5%	2.5%	2.5%	*2.5%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		4.2%	4.2%	4.2%	*4.2%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**(39)**			
2013 Adjusted Revenue Requirement - Subject to escalation		**778**			
Revenue Requirement - IR with escalation	817	**811**	**845**	**881**	***2.5%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
Site Restoration Cost - Tax impact	-	(18)	(17)	(15)	
	204	191	201	256	
Total Distribution Revenues -IR	**1,021**	**1,001**	**1,046**	**1,137**	***3.6%***
Achieved ROE	**8.9%**	**8.8%**	**9.2%**	**8.8%**	***8.9%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (IR vs COS)	**0.0%**	**-0.5%**	**-0.5%**	**-1.3%**	**-0.8%**

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R. Fischer
M. Lister

Sc4: Scenario 2 plus SRC impact

Allowed Revenues - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr- CAGR
	ADR				
Escalation factor					
Escalation factor (Inflation)		2.5%	2.5%	2.5%	***2.5%***
Productivity		0.0%	0.0%	0.0%	
I-X		2.5%	2.5%	2.5%	
Customer growth		1.7%	1.7%	1.7%	***1.7%***
Total Escalation factor		4.2%	4.2%	4.2%	***4.2%***
2013 Revenue Requirement	**817**				
Allowed Revenues - IR with escalation		**851**	**887**	**925**	***4.2%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
SRC impact	-	(61)	(55)	(48)	
	1,021	148	163	223	
Total Allowed Revenues -IR	**1,021**	**999**	**1,050**	**1,148**	***4.0%***
Achieved ROE	**8.9%**	**8.7%**	**9.4%**	**9.3%**	***9.1%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Achieved vs Allowed)		**-0.6%**	**-0.4%**	**-0.9%**	**-0.6%**

/u

27. In this scenario, the major reinforcement projects in the GTA and Ottawa were considered as new Y factors in the I-X model. Layering on the existing and new Y factors, and impacts of the new Depreciation Study results, IR revenue growth of ~~3.6~~4.0% was calculated. The forecast average annual ROE over the IR term under an I-X model is 0.~~8~~6% less than allowed ROE. /u /u

Analysis and Interpretation of Scenario 5

Witnesses: S. Kancharla
R. Fischer
M. Lister

Sc5: Breakeven escalation factor such that ROEs in Scenario 4 from I-X and allowed ROE are equal

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		3.8%	2.7%	4.9%	*3.8%*
Productivity		0.0%	0.0%	0.0%	
		3.8%	2.7%	4.9%	*3.8%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		5.5%	4.5%	6.7%	*5.6%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**(39)**			
2013 Adjusted Revenue Requirement - Subject to escalation		**778**			
Revenue Requirement - IR with escalation	817	**821**	**858**	**916**	***3.9%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
Site Restoration Cost - Tax impact	-	(18)	(17)	(15)	
	204	191	201	256	
Total Distribution Revenues -IR	**1,021**	**1,012**	**1,059**	**1,172**	***4.7%***
Achieved ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (IR vs COS)	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**

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R. Fischer
M. Lister

Sc5: Breakeven escalation factor such thatannual average ROEs in Scenario 4 are equal to forecast allowed ROE

Allowed Revenues - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr- CAGR
	ADR				
Escalation factor					
Escalation factor (Inflation)		4.0%	2.0%	4.0%	***3.3%***
Productivity		0.0%	0.0%	0.0%	
I-X		4.0%	2.0%	4.0%	
Customer growth		1.7%	1.7%	1.7%	***1.7%***
Total Escalation factor		5.8%	3.7%	5.8%	***5.1%***
2013 Revenue Requirement	**817**				
Allowed Revenues - IR with escalation		**864**	**896**	**948**	***5.1%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
SRC impact	-	(61)	(55)	(48)	
	1,021	148	162	223	
Total Allowed Revenues -IR	**1,021**	**1,012**	**1,058**	**1,171**	***4.7%***
Achieved ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Achieved vs Allowed)		**0.0%**	**0.0%**	**0.0%**	**0.0%**

/u

28. In this scenario, the major reinforcement projects were considered as new Y factors and the impacts of the new depreciation study are incorporated. The required I-X escalation factor is solved to produce ROEs from the I-X model equal to forecast allowed ROE. The 3 year average escalation factor required in this case is 3.~~8~~3%. This required escalation factor is significantly greater than the forecast inflation and productivity factor of 2.5% recommended and forecast by Concentric. /u

Witnesses: S. Kancharla
R. Fischer
M. Lister

Analysis and Interpretation of Scenario 6

Sc6: Same asumptions as Scenario 4 except I-X is assumed equal to the actual effective I-X during 1st Generation IR term

Revenue Requirement - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr - CAGR
Escalation factor					
Escalation factor (Inflation)		1.7%	1.7%	1.7%	*1.7%*
Productivity		50.0%	50.0%	50.0%	
		0.9%	0.9%	0.9%	*0.9%*
Customer Growth		1.7%	1.7%	1.7%	*1.7%*
		2.6%	2.6%	2.6%	*2.6%*
2013 Revenue Requirement	**817**	**817**			
Adjustment for Reduction in depreciation expense with SRC in 2013 base		**(39)**			
2013 Adjusted Revenue Requirement - Subject to escalation		**778**			
Revenue Requirement - IR with escalation	817	**798**	**819**	**841**	***1.0%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
Site Restoration Cost - Tax impact	-	(18)	(17)	(15)	
	204	191	201	256	
Total Distribution Revenues -IR	**1,021**	**989**	**1,020**	**1,096**	***2.4%***
Achieved ROE	**8.9%**	**8.2%**	**8.1%**	**7.3%**	***7.9%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (IR vs COS)	**0.0%**	**-1.1%**	**-1.6%**	**-2.8%**	**-1.8%**

Witnesses: S. Kancharla
R. Fischer
M. Lister

Sc6: Same assumptions as Scenario 4 except I-X is assumed equal to the actual effective I-X during 1st Generation IR term

Allowed Revenues - IR ($M)	Rebase 2013	Second Generation IR 2014	2015	2016	3 yr- CAGR
	ADR				
Escalation factor					
Escalation factor (Inflation)		1.7%	1.7%	1.7%	***1.7%***
Productivity (50% of Inflation)		-0.9%	-0.9%	-0.9%	
I-X		0.9%	0.9%	0.9%	
Customer growth		1.7%	1.7%	1.7%	***1.7%***
Total Escalation factor		2.6%	2.6%	2.6%	***2.6%***
2013 Revenue Requirement	**817**				
Allowed Revenues - IR with escalation		**838**	**860**	**882**	***2.6%***
Y factor					
Carrying cost for Gas in Storage	20	20	20	21	
Pension cost	43	37	34	31	
DSM	31	32	33	33	
Y factor for Customer Care	110	114	119	124	
Y factor for GTA&Ottawa	-	5	12	62	
SRC impact	-	(61)	(55)	(48)	
	1,021	148	162	223	
Total Allowed Revenues -IR	**1,021**	**986**	**1,022**	**1,105**	***2.6%***
Achieved ROE	**8.9%**	**8.1%**	**8.2%**	**7.7%**	***8.0%***
Forecast Allowed ROE	**8.9%**	**9.3%**	**9.7%**	**10.1%**	***9.7%***
ROE Variance (Achieved vs Allowed)		**-1.2%**	**-1.5%**	**-2.4%**	**-1.7%**

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29. In this scenario, the major reinforcement projects in the GTA and Ottawa were considered as new Y factors in the I-X model, with I-X assumed to be equal to the actual effective I-X during the 1st Generation IR term. The 3 year average escalation factor is 1.7% and with customer growth, the IR escalation is 2.6%. Layering on the existing and new Y factors, and impacts of the new depreciation study results, IR revenue growth of 2.46% was calculated. The forecast average

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annual ROE over the IR term under the I-X model is 1.~~8~~7% less than forecast allowed ROE. /u

Summary of Financial Scenario Analysis

30. The following table provides the summary of all the scenarios analysed above.

Summary of Scenarios

	Annual Average Allowed ROE Deficiency 2014-2016
S1: No New Y factors	-1.8%
S2: GTA and Ottawa as new Y factors	-0.7%
S4: New Y factors and impacts of changes to site restoration costs	-0.8%
S6: Same as S4 except I-X equal to the actual effective I-X during 1st Generation IR	-1.8%
	Average Breakeven Escalation factor to achieve the Allowed ROE
S3: Breakeven for S2	3.4%
S5: Breakeven for S4	3.8%

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R. Fischer
M. Lister

Summary of Scenarios

	Annual Average Allowed ROE Deficiency 2014-2016
S1: No New Y factors	-1.8%
S2: GTA and Ottawa as new Y factors	-0.7%
S4: New Y factors and impacts of changes to site restoration costs	-0.6%
S6: Same as S4 except I-X equal to the actual effective I-X during 1st Generation IR	-1.7%

/u

	Average Breakeven Escalation factor to achieve the Allowed ROE
S3: Breakeven for S2	3.4%
S5: Breakeven for S4	3.3%

31. Significant deficiencies below forecast allowed ROEs were determined for each I-X scenario, even assuming Y factor treatment for the major GTA and Ottawa reinforcement projects. This indicates that under continued application of the 1st Generation IR plan, EGD would be highly unlikely to earn the fair return. From another perspective, to earn a fair return and have a reasonable opportunity for timely recovery of capital investment, the escalation factor in an I-X model would need to be significantly higher than traditional values for I and X factors. To mitigate this under-earning, if the only lever was operating expenses, annual operating expenses would need to be reduced by approximately $~~51~~43 million, which is clearly unattainable and not reasonable. /u

32. As demonstrated above, the primary reason why a model with features consistent with Enbridge's 1st Generation IR plan, fails to offer an appropriate opportunity to earn a Fair Return, is due to the increased capital needs of the business. In large

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part, this is caused by increases in depreciation expense, which is addressed in the next section of this evidence.

The Challenge of Increasing Depreciation and Amortization Expense in an I-X Framework

33. Depreciation and amortization expense is a major revenue requirement component in a traditional cost of service build up of cost elements. For EGD, in 2013, depreciation and amortization is forecast to equal $279 million, representing almost 30% of the total estimated revenue requirement. Even with the reduction in depreciation expense due to the proposed adjustment to depreciation rates, in 2014 (related to site restoration costs), depreciation and amortization expense is forecast to increase from an adjusted level of $~~240~~250 million[1] in 2013 to $304 million in 2016, an increase of $~~64~~54 million over 3 years. The majority of this increase is due to the capital additions forecast during those years. /u /u

34. In Scenario 4, which includes Y factors for the major reinforcement projects and the impact of changes to SRC, revenue from an I-X and revenue cap per customer escalator is forecast to grow from $~~778~~817 million ~~(adjusted for reduction in depreciation expense with SRC)~~ in 2013 to $~~881~~925 million in 2016, an increase of $~~103~~108 milllion. In other words, around ~~60~~50% of the forecast revenue growth must be attributed to growth in depreciation and amortization, leaving an estimated $~~39~~54 million to "pay for" increases in the remaining cost elements, including O&M, cost of capital and tax. Stated another way, though depreciation and amortization expense represents less than 30% of the estimated revenue requirement in 2013, ~~60~~50% of the forecast revenue growth from the formula must cover forecast growth /u /u

[1] The "adjusted level" is determined by applying the impact of the depreciation rate change to the 2013 base.

Witnesses: S. Kancharla
R. Fischer
M. Lister

in depreciation and amortization over the IR term. That leaves an insufficient amount to cover increases in all other items.

35. Depreciation and amortization expense is growing at more than twice the rate of forecast revenue growth. The remaining incremental revenue is insufficient to cover the growing costs associated with O&M, cost of capital and tax, and therefore growing depreciation and amortization expense is a major contributor to the forecast revenue deficiencies and challenge of a formulaic IR model for EGD.

Conclusion

36. The analyses demonstrate that significant revenue and ROE deficiencies are likely to occur if EGD were to adopt an I-X model for the 2nd Generation IR Plan similar to that adopted in EGD's 1st Generation IR.

37. The analyses also show that, the escalation factor that is required to allow for capital recovery and the opportunity to earn a Fair Return is well in excess of traditional values for I and X. This condition has arisen as a result of significantly higher reinforcement requirements, and safety, integrity, and reliability drivers. EGD does not believe that the introduction of additional adders to the formula could accommodate the total required increase in capital spending, as the inevitable result would include many more Y factors and capital trackers, adding further complexity to the IR model framework. This would cause the IR framework to become too unwieldy and invite criticism of a model that includes too much patchwork and complexity.

38. Instead, the Company is proposing a Customized IR plan for its 2nd generation IR model which includes productivity, appropriate incentives, a mechanism for

ratepayers to share in additional savings beyond productivity build into the forecast, and other features to mitigate the probability of unintended consequences. The Customized IR plan, in addition to greatly simplifying the IR model construct, is appropriate to meet the needs of the utility.

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EGDI to calculate whether, if the average ROE is 124.5 basis points above allowed ROE during the IRM term, then the effect of the SEIM is for the ratepayers to give back all or more than all of the earnings sharing that they received.

RESPONSE

As stated at Exhibit A2, Tab 11, Schedule 3, the purpose of the SEIM is to include stronger incentives for the Company to implement long-term sustainable efficiencies which survive beyond the IR term and to encourage productivity investments in the later years of the IR term. These sustainable efficiencies will benefit ratepayers in terms of delivering safe and reliable energy to customers at rates lower than they would otherwise be beyond the IR term. ROE is only used as an input to calculate the potential SEIM reward. The SEIM reward will not be available to the Company unless it can meet the productivity and quality of service criteria as detailed on page 7 at Exhibit A2, Tab 11, Schedule 3.

As illustrated in the ~~tables~~table below, the potential SEIM reward ~~approximates~~is calculated using the ~~ratepayer ESM amounts assuming~~ actual ~~average~~, after earnings sharing ROE ~~is 124.5 bp above allowed ROE for very specific assumptions, however, different inputs/assumptions (i.e., rate base growth, fluctuations in actual ROE's over the term that still equate to~~. As a result, with an average overage of 124.5 bp~~, etc.) can result in very different results (i.e., SEIM amounts~~ (and including specific assumptions), the ESM amounts to ratepayers are approximately $1.2 million greater than ~~or less~~the potential SEIM reward.

If this very specific example were to unfold, ratepayers would receive the benefit of $15.0 million in earnings sharing plus an amount greater than ~~ESM amounts paid).~~$13.8 million in base rates provided the SEIM reward can be justified with long-term, sustainable benefits and service quality and performance have not suffered during the IR term.

Witnesses: S. Kancharla
R. Small

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Illustration of ESM and SEIM Calculations assuming average actual versus allowed ROE of 124.5 basis points

($ Millions)

ESM Calculations

	2014	2015	2016	2017	2018	Total
Rate Base	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	
Equity 36%	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	
Allowed ROE	10.00%	10.00%	10.00%	10.00%	10.00%	
Actual ROE	11.245%	11.245%	11.245%	11.245%	11.245%	
Net overearnings after 100bp deadband	4.4	4.4	4.4	4.4	4.4	
Gross overearnings (tax rate 26.5%)	6.0	6.0	6.0	6.0	6.0	
ESM amounts returned to ratepayers	3.0	3.0	3.0	3.0	3.0	**15.0**

SEIM Calculation

2014 - 2018 average actual ROE	11.245%	
2014 - 2018 average allowed ROE	10.000%	
Variance	1.245%	
ROE premium (Variance * 50% * 50%)	0.311%	(which is less than 0.5%)
2019 rate base	5,000.0	
2019 equity component of rate base	1,800.0	
Annual SEIM reward before gross-up for taxes	5.6	
Annual grossed-up SEIM reward	7.6	
Total SEIM reward (2 X Annual Reward)	**15.2**	

ESM Calculations

($ Millions)	2014	2015	2016	2017	2018	Total
Rate Base	5,000.0	5,000.0	5,000.0	5,000.0	5,000.0	
Equity 36%	1,800.0	1,800.0	1,800.0	1,800.0	1,800.0	
Allowed ROE	10.00%	10.00%	10.00%	10.00%	10.00%	
Actual ROE before sharing	11.245%	11.245%	11.245%	11.245%	11.245%	
Net overearnings after 100bp deadband	4.4	4.4	4.4	4.4	4.4	
Gross overearnings (tax rate 26.5%)	6.0	6.0	6.0	6.0	6.0	
ESM amounts returned to ratepayers	3.0	3.0	3.0	3.0	3.0	15.0
Actual ROE after sharing	11.122%	11.122%	11.122%	11.122%	11.122%	

SEIM Calculation

Witnesses: S. Kancharla
R. Small

2014 - 2018 average actual ROE after sharing	11.122%	
2014 - 2018 average allowed ROE	10.000%	
Variance	1.122%	
ROE premium (Variance * 50% * 50%)	0.281%	(which is less than 0.5%)
2019 rate base	5,000.0	
2019 equity component of rate base	1,800.0	
Annual SEIM reward before gross-up for taxes	5.0	
Annual grossed-up SEIM reward	6.9	
Total SEIM reward (2 X Annual Reward)	13.8	

Witnesses: S. Kancharla
R. Small