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ENBRIDGE

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2013

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

Financial Reporting
Management of Enbridge 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.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2013, based on the framework established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2013.

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 and the standards of the Public Company Accounting Oversight Board (United States).

"signed"

Al Monaco
President & Chief Executive Officer

"signed"

J. Richard Bird
Executive Vice President &
Chief Financial Officer

February 14, 2014

Independent Auditor's Report

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2013 and 2012 consolidated financial statements and its internal control over financial reporting as at December 31, 2013 and an audit of its 2011 consolidated financial statements. Our opinions, based on our audits, are presented below.

Report on the consolidated financial statements
We have audited the accompanying consolidated financial statements of Enbridge Inc., 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, changes in 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 and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, 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 company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and 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 on the consolidated financial statements.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2013 and December 31, 2012 and the results of its 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.

Report on internal control over financial reporting
We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting
Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

Auditor's responsibility
Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent limitations
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion
In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Alberta, Canada
February 14, 2014

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**26,039**	18,494	20,374
Gas distribution sales	**2,265**	1,910	1,906
Transportation and other services	**4,614**	4,256	4,509
	32,918	24,660	26,789
Expenses			
Commodity costs	**25,222**	17,959	19,627
Gas distribution costs	**1,585**	1,220	1,281
Operating and administrative	**3,014**	2,739	2,259
Depreciation and amortization	**1,370**	1,236	1,147
Environmental costs, net of recoveries *(Note 29)*	**362**	(88)	(116)
	31,553	23,066	24,198
	1,365	1,594	2,591
Income from equity investments *(Note 12)*	**330**	195	233
Other income/(expense) *(Note 26)*	**(135)**	238	116
Interest expense *(Note 17)*	**(947)**	(841)	(928)
	613	1,186	2,012
Income taxes *(Note 24)*	**(123)**	(171)	(523)
Earnings from continuing operations	**490**	1,015	1,489
Discontinued operations *(Note 10)*			
Earnings/(loss) from discontinued operations before income taxes	**6**	(123)	(9)
Income taxes (expense)/recovery from discontinued operations	**(2)**	44	3
Earnings/(loss) from discontinued operations	**4**	(79)	(6)
Earnings before extraordinary loss	**494**	936	1,483
Extraordinary loss, net of tax *(Note 6)*	**-**	-	(262)
Earnings	**494**	936	1,221
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**135**	(229)	(407)
Earnings attributable to Enbridge Inc.	**629**	707	814
Preference share dividends	**(183)**	(105)	(13)
Earnings attributable to Enbridge Inc. common shareholders	**446**	602	801
Earnings attributable to Enbridge Inc. common shareholders			
Earnings from continuing operations	**442**	681	1,069
Earnings/(loss) from discontinued operations, net of tax	**4**	(79)	(6)
Extraordinary loss, net of tax *(Note 6)*	**-**	-	(262)
	446	602	801
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**0.55**	0.88	1.43
Discontinued operations	**-**	(0.10)	(0.01)
Extraordinary item	**-**	-	(0.35)
	0.55	0.78	1.07
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 20)*			
Continuing operations	**0.55**	0.87	1.40
Discontinued operations	**-**	(0.10)	(0.01)
Extraordinary item	**-**	-	(0.34)
	0.55	0.77	1.05

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	494	936	1,221
Other comprehensive income/(loss), net of tax			
Change in unrealized gains/(loss) on cash flow hedges	697	(176)	(582)
Change in unrealized gains/(loss) on net investment hedges	(96)	13	(19)
Other comprehensive income/(loss) from equity investees	11	2	(17)
Reclassification to earnings of realized cash flow hedges	72	7	14
Reclassification to earnings of unrealized cash flow hedges	39	20	12
Reclassification to earnings of pension plans and other postretirement benefits amortization amounts	27	18	21
Actuarial gains/(loss) on pension plans and other postretirement benefits	114	(56)	(165)
Change in foreign currency translation adjustment	710	(158)	144
Other comprehensive income/(loss)	1,574	(330)	(592)
Comprehensive income	2,068	606	629
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	(276)	(165)	(327)
Comprehensive income attributable to Enbridge Inc.	1,792	441	302
Preference share dividends	(183)	(105)	(13)
Comprehensive income attributable to Enbridge Inc. common shareholders	1,609	336	289

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

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 20)*			
Balance at beginning of year	**3,707**	1,056	125
Preference shares issued	**1,434**	2,651	931
Balance at end of year	**5,141**	3,707	1,056
Common shares *(Note 20)*			
Balance at beginning of year	**4,732**	3,969	3,683
Common shares issued	**582**	388	-
Dividend reinvestment and share purchase plan	**361**	297	229
Shares issued on exercise of stock options	**69**	78	57
Balance at end of year	**5,744**	4,732	3,969
Additional paid-in capital			
Balance at beginning of year	**522**	242	131
Stock-based compensation	**28**	26	18
Options exercised	**(17)**	(17)	(7)
Issuance of treasury stock *(Note 12)*	**208**	236	-
Dilution gains and other	**5**	35	100
Balance at end of year	**746**	522	242
Retained earnings			
Balance at beginning of year	**3,173**	3,643	3,729
Earnings attributable to Enbridge Inc.	**629**	707	814
Preference share dividends	**(183)**	(105)	(13)
Common share dividends declared	**(1,035)**	(895)	(759)
Dividends paid to reciprocal shareholder	**19**	20	25
Redemption value adjustment attributable to redeemable noncontrolling interests *(Note 19)*	**(53)**	(197)	(153)
Balance at end of year	**2,550**	3,173	3,643
Accumulated other comprehensive loss *(Note 22)*			
Balance at beginning of year	**(1,762)**	(1,496)	(984)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**1,163**	(266)	(512)
Balance at end of year	**(599)**	(1,762)	(1,496)
Reciprocal shareholding *(Note 12)*			
Balance at beginning of year	**(126)**	(187)	(154)
Issuance of treasury stock	**40**	61	-
Acquisition of equity investment	**-**	-	(33)
Balance at end of year	**(86)**	(126)	(187)
Total Enbridge Inc. shareholders' equity	**13,496**	10,246	7,227
Noncontrolling interests *(Note 19)*			
Balance at beginning of year	**3,258**	3,141	2,424
Earnings/(loss) attributable to noncontrolling interests	**(111)**	241	416
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**166**	(39)	(84)
Change in foreign currency translation adjustment	**223**	(60)	66
Reclassification to earnings of realized cash flow hedges	**4**	23	(63)
Reclassification to earnings of unrealized cash flow hedges	**14**	13	4
	407	(63)	(77)
Comprehensive income attributable to noncontrolling interests	**296**	178	339
Distributions	**(468)**	(421)	(355)
Contributions	**922**	382	735
Dilution gains	**-**	6	22
Acquisitions *(Note 7)*	**-**	(25)	(27)
Other	**6**	(3)	3
Balance at end of year	**4,014**	3,258	3,141
Total equity	**17,510**	13,504	10,368
Dividends paid per common share	**1.26**	1.13	0.98

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	**494**	936	1,221
(Earnings)/loss from discontinued operations	**(4)**	79	6
Depreciation and amortization	**1,370**	1,236	1,147
Deferred income taxes *(Note 24)*	**131**	3	365
Changes in unrealized (gains)/loss on derivative instruments, net	**1,262**	665	(73)
Cash distributions in excess of equity earnings	**355**	439	102
Regulatory asset write-off *(Note 6)*	**-**	-	262
Impairment	**6**	39	11
Other	**(9)**	109	11
Changes in regulatory assets and liabilities	**(11)**	44	38
Changes in environmental liabilities, net of recoveries *(Note 29)*	**148**	(26)	(118)
Changes in operating assets and liabilities *(Note 27)*	**(409)**	(660)	401
Cash provided by continuing operations	**3,333**	2,864	3,373
Cash provided by/(used in) discontinued operations *(Note 10)*	**8**	10	(2)
	3,341	2,874	3,371
Investing activities			
Additions to property, plant and equipment	**(8,235)**	(5,194)	(3,527)
Long-term investments	**(1,018)**	(531)	(1,515)
Additions to intangible assets	**(212)**	(163)	(154)
Acquisitions, net of cash acquired *(Note 7)*	**-**	(340)	(33)
Affiliate loans, net	**8**	8	7
Proceeds on sale of investments and net assets	**41**	18	-
Government grant	**-**	-	145
Changes in restricted cash	**(15)**	(2)	(2)
	(9,431)	(6,204)	(5,079)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**(350)**	412	224
Net change in commercial paper and credit facility draws	**1,562**	(294)	(630)
Net change in Southern Lights project financing	**(5)**	(13)	(62)
Debenture and term note issues	**2,845**	2,199	1,604
Debenture and term note repayments	**(660)**	(349)	(234)
Repayment of acquired debt	**-**	(160)	-
Contributions from noncontrolling interests	**922**	448	873
Distributions to noncontrolling interests	**(468)**	(421)	(355)
Contributions from redeemable noncontrolling interests	**92**	213	210
Distributions to redeemable noncontrolling interests	**(72)**	(49)	(35)
Preference shares issued	**1,428**	2,634	926
Common shares issued	**628**	465	46
Preference share dividends	**(178)**	(93)	(7)
Common share dividends	**(674)**	(597)	(530)
	5,070	4,395	2,030
Effect of translation of foreign denominated cash and cash equivalents	**20**	(12)	25
Increase/(decrease) in cash and cash equivalents	**(1,000)**	1,053	347
Cash and cash equivalents at beginning of year	**1,776**	723	376
Cash and cash equivalents at end of year	**776**	1,776	723
Cash and cash equivalents - discontinued operations	**(20)**	-	-
Cash and cash equivalents - continuing operations	**756**	1,776	723
Supplementary cash flow information			
Income taxes (received)/paid	**107**	267	(28)
Interest paid	**1,097**	988	955

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	756	1,776
Restricted cash	34	19
Accounts receivable and other *(Note 8)*	4,956	4,014
Accounts receivable from affiliates	65	12
Inventory *(Note 9)*	1,115	779
Assets held for sale *(Note 10)*	24	-
	6,950	6,600
Property, plant and equipment, net *(Note 10)*	42,279	33,318
Long-term investments *(Note 12)*	4,212	3,175
Deferred amounts and other assets *(Note 13)*	2,662	2,461
Intangible assets, net *(Note 14)*	1,004	817
Goodwill *(Note 15)*	445	419
Deferred income taxes *(Note 24)*	16	10
	57,568	46,800
Liabilities and equity		
Current liabilities		
Bank indebtedness	338	479
Short-term borrowings *(Note 17)*	374	583
Accounts payable and other *(Note 16)*	6,664	5,052
Accounts payable to affiliates	46	-
Interest payable	228	196
Environmental liabilities *(Note 29)*	260	107
Current maturities of long-term debt *(Note 17)*	2,811	652
Liabilities held for sale *(Note 10)*	7	-
	10,728	7,069
Long-term debt *(Note 17)*	22,357	20,203
Other long-term liabilities *(Note 18)*	2,938	2,541
Deferred income taxes *(Note 24)*	2,925	2,483
Liabilities held for sale *(Note 10)*	57	-
	39,005	32,296
Commitments and contingencies *(Note 29)*		
Redeemable noncontrolling interests *(Note 19)*	1,053	1,000
Equity		
Share capital *(Note 20)*		
Preference shares	5,141	3,707
Common shares (831 and 805 outstanding at December 31, 2013 and 2012, respectively)	5,744	4,732
Additional paid-in capital	746	522
Retained earnings	2,550	3,173
Accumulated other comprehensive loss *(Note 22)*	(599)	(1,762)
Reciprocal shareholding *(Note 12)*	(86)	(126)
Total Enbridge Inc. shareholders' equity	13,496	10,246
Noncontrolling interests *(Note 19)*	4,014	3,258
	17,510	13,504
	57,568	46,800

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

Approved by the Board of Directors:

"signed"
David A. Arledge
Chair

"signed"
David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments and Corporate. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Seaway Pipeline, Spearhead Pipeline, Feeder Pipelines and Other.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD) which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Gas Pipelines, Processing and Energy Services consists of investments in natural gas pipelines, gathering and processing facilities and the Company's energy services businesses, along with renewable energy and transmission facilities.

Investments in natural gas pipelines include the Company's interests in the United States portion of the Alliance System (Alliance Pipeline US), the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas fractionation and extraction business located near the terminus of the Alliance System. The energy services businesses undertake physical commodity marketing activities and logistical services, refinery supply services and manage the Company's volume commitments on the Alliance System, Vector and other pipeline systems.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company's 20.6% (2012 - 21.8%) ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge's 66.7% (2012 - 66.7%) investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership and an overall 67.3% (2012 - 67.7%) economic interest in Enbridge Income Fund (the Fund), held both directly and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge, through its subsidiaries, manages the day-to-day operations of and develops and assesses opportunities for each of these investments, including both organic growth and acquisition opportunities.

EEP transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines, including the Lakehead Pipeline System (Lakehead System) which is the United States portion of the Enbridge mainline system, and transports, gathers, processes and markets natural gas and NGL. The primary operations of the Fund include renewable power generation, crude oil and liquids pipeline and storage businesses in western Canada and a 50% interest in the Canadian portion of the Alliance System (Alliance Pipeline Canada).

CORPORATE

Corporate consists of the Company's investment in Noverco Inc. (Noverco), new business development activities, general corporate investments and financing costs not allocated to the business segments.

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. As a Securities and Exchange Commission (SEC) registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of 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: carrying values of regulatory assets and liabilities *(Note 6)*; unbilled revenues *(Note 8)*; allowance for doubtful accounts *(Note 8)*; depreciation rates and carrying value of property, plant and equipment *(Note 10)*; amortization rates of intangible assets *(Note 14)*; measurement of goodwill *(Note 15)*; valuation of stock-based compensation *(Note 21)*; fair value of financial instruments *(Note 23)*; provisions for income taxes *(Note 24)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 25)*; commitments and contingencies *(Note 29)*; fair value of asset retirement obligations (ARO); and estimates of losses related to environmental remediation obligations *(Note 29)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and a variable interest entity (VIE) for which the Company is the primary beneficiary. The consolidated financial statements also include the accounts of any limited partnerships where the Company represents the general partner and, based on all facts and circumstances, controls such limited partnerships. For certain investments where the Company retains an undivided interest in assets and liabilities, Enbridge records its proportionate share of assets, liabilities, revenues and expenses.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests and redeemable noncontrolling interests. Investments and entities over which the Company exercises significant influence are accounted for using the equity method.

REGULATION

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the New Brunswick Energy and Utilities Board (EUB), and the Ontario Energy Board (OEB). Regulatory bodies 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 regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

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 included 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. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. 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. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing and the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

For certain regulated operations to which U.S. GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with U.S. GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with U.S. GAAP and no deferred regulatory asset is recorded *(Note 4)*.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of certain operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration. Certain Liquids Pipelines revenues are recognized under the terms of committed delivery contracts rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. The Company recognizes revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. From July 1, 2011 onward, Canadian Mainline (excluding Lines 8 and 9) earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective on that date, the Company prospectively discontinued the application of rate-regulated accounting for those assets with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenues are recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities 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 distribution franchise area.

For natural gas and marketing businesses, an estimate of revenues and commodity costs for the month of December is included in the Consolidated Statements of Earnings for each year based on the best available volume and price data for the commodity delivered and received.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. 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.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. 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.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item. The Company did not have any fair value hedges at December 31, 2013 or 2012.

Net Investment Hedges

The Company uses net investment hedges to manage its exposure to changes in the carrying values of United States dollar denominated foreign operations. The effective portion of the change in the fair value of the hedging instrument is recorded in OCI. Any ineffectiveness is recorded in current period earnings. Amounts recorded in Accumulated other comprehensive income/(loss) (AOCI) are recognized in earnings when there is a reduction of the hedged net investment resulting from a disposal of the foreign operation.

Classification of Derivatives

The Company recognizes the fair market 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 as Deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

EQUITY INVESTMENTS
Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, the Company capitalizes interest costs associated with its investment during such period.

OTHER INVESTMENTS
Generally, the Company classifies equity investments in entities over which it does not exercise significant influence and that do not trade on an actively quoted market as other investments carried at cost. Financial assets in this category are initially recorded at fair value with no subsequent re-measurement. Any investments which do trade on an active market are classified as available for sale investments measured at fair value through OCI. Dividends received from investments carried at cost are recognized in earnings when the right to receive payment is established.

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and VIEs. The portion of equity in entities not owned by the Company is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position and, in the case of redeemable noncontrolling interests, within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

The Fund's noncontrolling interest holders have the option to redeem the Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interests are recognized at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares. On a quarterly basis, changes in estimated redemption values are reflected as a charge or credit to retained earnings.

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.

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 balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar presentation currency are included in the cumulative translation adjustment component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect on the balance sheet date, while revenues and expenses are translated using monthly average exchange 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.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific customer agreements, are presented as Restricted cash on the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES
Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost.

ALLOWANCE FOR DOUBTFUL ACCOUNTS
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.

INVENTORY
Inventory is comprised of natural gas in storage held in EGD and crude oil and natural gas held primarily by energy services businesses. Natural gas in storage in EGD is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other commodities inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs in the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost. 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 future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets 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.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; contractual receivables under the terms of long-term delivery contracts; derivative financial instruments; and deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt and are recorded in Interest expense.

INTANGIBLE ASSETS

Intangible assets consist primarily of acquired long-term transportation or power purchase agreements, natural gas supply opportunities and certain software costs. Natural gas supply opportunities are growth opportunities, identified upon acquisition, present in gas producing zones where certain of EEP's gas systems are located. 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 lives, commencing when the asset is available for use.

GOODWILL

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step involves determining the fair value of the Company's reporting units inclusive of goodwill and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the reporting unit's assets and liabilities.

IMPAIRMENT

The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

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. For the Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans), in 2013 new mortality assumptions were adopted by the Company for measurement of the December 31, 2013 benefit obligations, moving from the tables previously issued by the Canadian Institute of Actuaries 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 for its Canadian Plans, 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 the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans;
- 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 contribution occurs.

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

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets or Other long-term liabilities, 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.

Certain regulated utility operations of the Company expect to recover pension expense in future rates and therefore record a corresponding regulatory asset to the extent such recovery is deemed to be probable. For years prior to 2012, a regulatory asset related to EGD's OPEB obligation was not recorded given recovery in rates was not probable. Commencing in 2012, pursuant to a specific rate order allowing EGD to recover 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
Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO 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, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance based stock options (PBSO) 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 PBSO granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period with a corresponding credit to Additional paid-in capital. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSU 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 with an offset to Accounts payable and other or to Other long-term liabilities. The value of the PSU is also dependent on the Company's performance relative to performance targets set out under the plan.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES
The Company expenses or capitalizes, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. The Company expenses costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. The Company records liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. The Company's estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. The Company evaluates recoveries from insurance coverage separately from the liability and, when recovery is probable, the Company records and reports an asset separately from the associated liability in the Consolidated Statements of Financial Position.

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

3. CHANGES IN ACCOUNTING POLICIES

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.

4. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In connection with the preparation of the Company's consolidated financial statements for the three months ended March 31, 2013, an error was identified in the manner in which the Company recorded deferred regulatory assets associated with the difference between depreciation expense calculated in accordance with U.S. GAAP and negotiated depreciation rates recovered in transportation tolls for certain of its regulated operations. Further, to the extent the deferred regulatory asset gave rise to temporary differences, an offsetting regulatory asset with respect to deferred income taxes was also recognized. During the three months ended September 30, 2013, the Company identified that certain intercompany commodity sales and commodity purchase transactions within Energy Services were not appropriately eliminated upon consolidation. This presentation matter had no effect on the margin, earnings or cash flows for any prior period.

In accordance with accounting guidance found in Accounting Standards Codification (ASC) 250-10 (SEC Staff Accounting Bulletin No. 99, *Materiality*), the Company assessed the materiality of these errors and concluded that they were 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 effects of these matters. These non-cash revisions do not impact cash flows for any prior period.

The following tables present the effect of these corrections 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, Depreciation and amortization, Cash distributions in excess of equity earnings, Deferred income taxes, Changes in regulatory assets and liabilities 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.

The previously reported figures presented below exclude the effect of any subsequent presentation changes associated with discontinued operations. 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, except per share amounts)						
Commodity sales	19,101	(607)	18,494	20,611	(237)	20,374
Transportation and other services revenues	4,295	(7)	4,288	4,536	(8)	4,528
Commodity costs	18,566	(607)	17,959	19,864	(237)	19,627
Depreciation and amortization	1,206	36	1,242	1,112	42	1,154
Income from equity investments	160	35	195	210	23	233
Income taxes expense	(128)	1	(127)	(526)	6	(520)
Earnings	943	(7)	936	1,242	(21)	1,221
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(228)	(1)	(229)	(409)	2	(407)
Earnings attributable to Enbridge Inc.	715	(8)	707	833	(19)	814
Earnings attributable to Enbridge Inc. common shareholders	610	(8)	602	820	(19)	801
Earnings per common share attributable to Enbridge Inc. common shareholders	0.79	(0.01)	0.78	1.09	(0.02)	1.07
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.78	(0.01)	0.77	1.08	(0.03)	1.05

	As at December 31, 2012		
	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)			
Long-term investments	3,386	(211)	3,175
Deferred amounts and other assets	2,622	(161)	2,461
Deferred income tax liabilities	2,601	(118)	2,483
Retained earnings	3,464	(291)	3,173
Accumulated other comprehensive loss	(1,799)	37	(1,762)

5. SEGMENTED INFORMATION

Year ended December 31, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	2,272	2,741	20,310	7,595	-	32,918
Commodity and gas distribution costs	-	(1,585)	(20,244)	(4,978)	-	(26,807)
Operating and administrative	(1,006)	(534)	(221)	(1,226)	(27)	(3,014)
Depreciation and amortization	(429)	(321)	(75)	(530)	(15)	(1,370)
Environmental costs, net of recoveries	(79)	-	-	(283)	-	(362)
	758	301	(230)	578	(42)	1,365
Income from equity investments	118	-	154	56	2	330
Other income/(expense)	39	20	39	37	(270)	(135)
Interest income/(expense)	(319)	(160)	(81)	(409)	22	(947)
Income taxes recovery/(expense)	(165)	(32)	50	(133)	157	(123)
Earnings/(loss) from continuing operations	431	129	(68)	129	(131)	490
Discontinued operations						
Earnings from discontinued operations before income taxes	-	-	6	-	-	6
Income taxes from discontinued operations	-	-	(2)	-	-	(2)
Earnings from discontinued operations	-	-	4	-	-	4
Earnings/(loss)	431	129	(64)	129	(131)	494
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(4)	-	-	139	-	135
Preference share dividends	-	-	-	-	(183)	(183)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	427	129	(64)	268	(314)	446
Additions to property, plant and equipment[4]	4,360	533	744	2,565	34	8,236
Total assets	20,950	7,942	7,015	18,527	3,134	57,568

Year ended December 31, 2012	Liquids Pipelines[2]	Gas Distribution	Gas Pipelines, Processing and Energy Services[2,3]	Sponsored Investments[2]	Corporate[1,3]	Consolidated
(millions of Canadian dollars)						
Revenues	2,445	2,438	13,106	6,671	-	24,660
Commodity and gas distribution costs	-	(1,220)	(13,676)	(4,283)	-	(19,179)
Operating and administrative	(942)	(528)	(142)	(1,076)	(51)	(2,739)
Depreciation and amortization	(399)	(336)	(57)	(431)	(13)	(1,236)
Environmental costs, net of recoveries	-	-	-	88	-	88
	1,104	354	(769)	969	(64)	1,594
Income/(loss) from equity investments	46	-	141	55	(47)	195
Other income/(expense)	(7)	83	33	49	80	238
Interest income/(expense)	(250)	(164)	(50)	(397)	20	(841)
Income taxes recovery/(expense)	(192)	(66)	269	(169)	(13)	(171)
Earnings/(loss) from continuing operations	701	207	(376)	507	(24)	1,015
Discontinued operations						
Loss from discontinued operations before income taxes	-	-	(123)	-	-	(123)
Income taxes recovery from discontinued operations	-	-	44	-	-	44
Loss from discontinued operations	-	-	(79)	-	-	(79)
Earnings/(loss)	701	207	(455)	507	(24)	936
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(4)	-	(1)	(224)	-	(229)
Preference share dividends	-	-	-	-	(105)	(105)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	697	207	(456)	283	(129)	602
Additions to property, plant and equipment[4]	1,927	445	933	1,886	4	5,195
Total assets	15,124	7,416	5,349	15,648	3,263	46,800

Year ended December 31, 2011	Liquids Pipelines[2]	Gas Distribution	Gas Pipelines, Processing and Energy Services[2,3]	Sponsored Investments[2]	Corporate[1,3]	Consolidated
(millions of Canadian dollars)						
Revenues	1,934	2,516	13,343	8,996	-	26,789
Commodity and gas distribution costs	-	(1,282)	(12,814)	(6,812)	-	(20,908)
Operating and administrative	(752)	(508)	(116)	(847)	(36)	(2,259)
Depreciation and amortization	(364)	(320)	(68)	(383)	(12)	(1,147)
Environmental costs, net of recoveries	-	-	-	116	-	116
	818	406	345	1,070	(48)	2,591
Income/(loss) from equity investments	5	-	179	54	(5)	233
Other income/(expense)	31	(12)	39	68	(10)	116
Interest expense	(256)	(166)	(56)	(350)	(100)	(928)
Income taxes recovery/(expense)	(125)	(54)	(178)	(171)	5	(523)
Earnings/(loss) from continuing operations	473	174	329	671	(158)	1,489
Discontinued operations						
Loss from discontinued operations before income taxes	-	-	(9)	-	-	(9)
Income taxes recovery from discontinued operations	-	-	3	-	-	3
Loss from discontinued operations	-	-	(6)	-	-	(6)
Earnings/(loss) before extraordinary loss	473	174	323	671	(158)	1,483
Extraordinary loss, net of tax	-	(262)	-	-	-	(262)
Earnings/(loss)	473	(88)	323	671	(158)	1,221
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(3)	-	(1)	(403)	-	(407)
Preference share dividends	-	-	-	-	(13)	(13)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	470	(88)	322	268	(171)	801
Additions to property, plant and equipment[4]	909	478	959	1,157	27	3,530

1 *Included within the Corporate segment was Interest income of $443 million (2012 - $336 million; 2011 - $239 million) charged to other operating segments.*

2 *In December 2012 and October 2011, certain crude oil storage and renewable energy assets were transferred to the Fund within the Sponsored Investments segment. Earnings from the assets prior to the date of transfer of $33 million (2011 - $71 million) have not been reclassified among segments for presentation purposes.*

3 *Due to a change in organizational structure, effective January 1, 2013, for the year ended December 31, 2012 earnings of $1 million (2011 - nil) and additions to property, plant and equipment of $108 million (2011 - nil) were reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment.*

4 *Includes allowance for equity funds used during construction.*

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Canada	12,690	11,629	11,852
United States	20,228	13,031	14,937
	32,918	24,660	26,789

1 *Revenues are based on the country of origin of the product or service sold.*

Property, Plant and Equipment

December 31,	2013	2012
(millions of Canadian dollars)		
Canada	22,865	19,293
United States	19,414	14,025
	42,279	33,318

6. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation. The Company's significant regulated businesses and related accounting impacts are described below.

Canadian Mainline

Canadian Mainline includes the Canadian portion of the mainline system and is subject to regulation by the NEB. Canadian Mainline tolls (excluding Lines 8 and 9) are currently governed by the 10-year CTS, which establishes a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on the Lakehead System and delivery points on the Canadian Mainline downstream of the Lakehead System. The CTS was negotiated with shippers in accordance with NEB guidelines, was approved by the NEB in June 2011 and took effect July 1, 2011. Under the CTS, a regulatory asset is recognized to offset deferred income taxes as a NEB rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Prior to July 1, 2011, the effective date of the CTS, the Incentive Tolling Settlement (ITS) defined the methodology for calculation of tolls on the core component of the Canadian Mainline. Toll adjustments for variances from requirements defined in the ITS were filed annually with the regulator for approval, and regulatory assets and liabilities were recognized to the extent amounts were recoverable from or payable to customers through future rates. Surcharges were also determined for a number of system expansion components and were added to the base toll determined for the core system.

Southern Lights

The United States portion of the Southern Lights Pipeline (Southern Lights US) is regulated by the FERC and the Canadian portion of the Southern Lights Pipeline (Southern Lights Canada) is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of all operating and debt financing costs, plus a pre-determined after-tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. For the year ended December 31, 2013, rates were set pursuant to an OEB approved settlement agreement and decision (the 2013 Settlement) related to its 2013 cost of service rate application. The 2013 Settlement retained the previous deemed equity level but provided for an increase in the allowed 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 revenue cap incentive regulation (IR), did not apply to the 2013 Settlement.

Prior to 2013, EGD operated under an IR mechanism, calculated on a revenue per customer basis, with the OEB for a five-year period between 2008 and 2012. Under the IR mechanism, the Company 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.

EGD's after-tax rate of return on common equity embedded in rates was 8.9% for the year ended December 31, 2013 (2012 - 8.4%) based on a 36% deemed common equity component of capital for regulatory purposes (2012 - 36%).

The 2013 Settlement established the right to recover an existing OPEB liability of approximately $89 million ($63 million after-tax) over a 20-year time period commencing in 2013. The gain was presented within Other income/(expense) on the Consolidated Statements of Earnings for the year ended December 31, 2012. The 2013 Settlement further provided for OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

In July 2013, EGD 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 by the second quarter of 2014.

Enbridge Gas New Brunswick
Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and currently sets tolls at the lower of market-based or cost of service rates. As at December 31, 2011, EGNB discontinued rate-regulated accounting due to amendments in the rate setting methodology enacted by the Government of New Brunswick, and consequently wrote-off a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an income tax recovery of $21 million. The write-off of $262 million, net of tax, was presented as an extraordinary loss on the Consolidated Statements of Earnings for the year ended December 31, 2011.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31, *(millions of Canadian dollars)*	2013	2012
Regulatory assets/(liabilities)		
Liquids Pipelines		
Deferred income taxes[1]	727	598
Tolling deferrals[2]	(36)	(33)
Recoverable income taxes[3]	42	40
Gas Distribution		
Deferred income taxes[4]	214	201
Transaction services deferral[5]	(51)	(26)
Future removal and site restoration reserves[6]	(929)	(882)
Pension plans and OPEB[7]	94	212
Sponsored Investments		
Deferred income taxes[1]	28	39
Transportation revenue adjustments[8]	33	19

1 *The asset represents the regulatory offset to deferred income tax liabilities that are expected to be recovered under flow-through income tax treatment. The recovery period depends on future reversal of temporary differences.*
2 *The liability reflects net tax benefits expected to be refunded through future transportation tolls on Southern Lights Canada. The balance is expected to accumulate for approximately nine years before being refunded through tolls.*
3 *The asset represents future revenues to be collected from shippers for Southern Lights US to recover federal income taxes payable on the equity component of AFUDC. The recovery period is approximately 30 years.*
4 *The asset represents the regulatory offset to deferred income tax liabilities to the extent that deferred income taxes are expected to be recovered or refunded through regulator-approved rates. The recovery period depends on future temporary differences. Deferred income taxes in Gas Distribution are excluded from the rate base and do not earn a return on equity.*
5 *The transaction services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. The balance is expected to be refunded to customers in the following year.*
6 *The future removal and site restoration reserves balance results from amounts collected from customers by certain businesses, with the approval of the regulator, 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 has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur as future removal and site restoration costs are incurred.*
7 *The pension plans and OPEB balances represent the regulatory offset to pension plan and OPEB obligations to the extent the amounts are expected to be collected from customers in future rates. An OPEB balance of $89 million is being collected over a 20-year period which commenced in 2013, whereas the settlement period for the pension regulatory asset is not determinable. The balances are excluded from the rate base and do not earn a return on equity.*
8 *Transportation revenue adjustments are the cumulative differences between actual expenses incurred and estimated expenses included in transportation tolls. Transportation revenue adjustments are not included in the rate base. The recovery period is approximately five years and dependent on shipper throughput levels.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs
Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains or losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization
With the approval of regulators, certain operations capitalize a percentage of certain operating costs. These operations are 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.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2013, cumulative costs relating to this consulting contract of $154 million (2012 - $144 million) were included in Property, plant and equipment 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.

7. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

Silver State North Solar Project

On March 22, 2012, Enbridge acquired a 100% interest in the Silver State North Solar Project (Silver State), a solar farm located in Nevada for cash consideration of $195 million (US$190 million). Silver State expanded the Company's renewable energy business. Revenues and earnings of $10 million and $1 million, respectively, were recognized in the year ended December 31, 2012. No revenues or earnings were recognized in any prior period as the solar project commenced operations in the second quarter of 2012. Silver State is included within the Gas Pipelines, Processing and Energy Services segment.

March 22,	2012
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Accounts receivable and other[1]	54
Property, plant and equipment	141
	195
Purchase price:	
Cash	195

1 *The Company acquired the right to apply for a $54 million (US$55 million) United States Treasury grant under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property. The grant, which was applied for subsequent to commercial operations, was received in October 2012.*

Tonbridge Power Inc.

On October 13, 2011, Enbridge acquired 100% of the 36 million outstanding common shares of Tonbridge Power Inc. (Tonbridge), an independent company engaged in constructing an electric transmission line between Montana and Alberta, for $20 million in cash at a price of $0.54 per share. Tonbridge was included within the Corporate segment upon acquisition and was subsequently reclassified to the Gas Pipelines, Processing and Energy Services segment effective January 1, 2013, due to a change in organizational structure.

October 13,	2011
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Working capital deficiency	(5)
Property, plant and equipment	196
Intangible assets	17
Long-term debt	(182)
Other long-term liabilities	(21)
	5
Purchase price:	
Cash (net of $15 million cash acquired)	5

No revenues from Tonbridge were recognized in 2011 as the transmission line was not in service. A net loss of $1 million was recognized in earnings for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expense. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in earnings in 2011 had the acquisition occurred on January 1, 2011.

OTHER ACQUISITIONS AND DISPOSITIONS

In November 2013, EEP sold one of its non-core liquids assets, a storage facility in Kansas, to a third party for $41 million (US$40 million). A gain of $18 million (US$17 million) was presented within Other income/(expense) on the Consolidated Statements of Earnings.

In November 2012, Enbridge acquired certain sour gas gathering and compression facilities located in the Peace River Arch region of northwest Alberta (collectively, Pipestone and Sexsmith) for a purchase price of $118 million, which has been fully allocated to Property, plant and equipment. Pipestone and Sexsmith are currently in service or under construction and are presented within the Gas Pipelines, Processing and Energy Services segment.

In May 2012, Enbridge acquired the remaining 10% interest in the Greenwich Wind Energy Project (Greenwich) through Greenwich Windfarm, LP, for cash consideration of $27 million, increasing its ownership interest to 100%. The Company's interest in Greenwich was consolidated and presented within the Gas Pipelines, Processing and Energy Services segment until such time as it was transferred to the Fund in December 2012 *(Note 19)*.

In October 2011, the Company acquired the remaining 10% interest in Talbot Windfarm, LP (Talbot) for $28 million, increasing its ownership interest to 100%. The Company's interest in Talbot was consolidated and presented within the Gas Pipelines, Processing and Energy Services segment until such time as it was transferred to the Fund in October 2011.

Unaudited proforma consolidated revenues and earnings that give effect to all of the Company's other acquisitions as if they had occurred as of January 1 in the year of acquisition are not presented as the information would not be materially different from the information presented in the accompanying Consolidated Statements of Earnings.

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8. ACCOUNTS RECEIVABLE AND OTHER

December 31,	2013	2012
(millions of Canadian dollars)		
Unbilled revenues	2,773	2,289
Trade receivables	1,215	677
Taxes receivable	200	123
Regulatory assets	54	-
Short-term portion of derivative assets *(Note 23)*	385	383
Prepaid expenses and deposits	123	132
Current deferred income taxes *(Note 24)*	120	167
Dividends receivable	26	26
Other	98	266
Allowance for doubtful accounts	(38)	(49)
	4,956	4,014

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement), certain trade and accrued receivables (the Receivables) have been sold by certain of EEP's subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement, as amended on September 20, 2013 and again on December 2, 2013, provides for subsequent purchases to occur on a monthly basis through to December 2016; however, the accumulated purchases net of collections cannot exceed US$450 million at any one point. As at December 31, 2013, the value of trade and accrued receivables outstanding owned by the SPE totalled US$380 million ($404 million).

9. INVENTORY

December 31,	2013	2012
(millions of Canadian dollars)		
Natural gas	527	448
Other commodities	588	331
	1,115	779

Commodity costs on the Consolidated Statements of Earnings included non-cash charges of $4 million (2012 - $10 million; 2011 - $9 million) for the year ended December 31, 2013 to reduce the cost basis of inventory to market value.

10. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2013	2012
(millions of Canadian dollars)			
Liquids Pipelines			
Pipeline	2.6%	8,974	8,249
Pumping equipment, buildings, tanks and other	3.0%	6,248	5,094
Land and right-of-way	2.2%	253	225
Under construction	-	4,846	1,675
		20,321	15,243
Accumulated depreciation		(3,838)	(3,432)
		16,483	11,811
Gas Distribution			
Gas mains, services and other	3.8%	8,020	7,583
Land and right-of-way	1.1%	79	79
Under construction	-	179	102
		8,278	7,764
Accumulated depreciation		(2,074)	(1,912)
		6,204	5,852
Gas Pipelines, Processing and Energy Services			
Pipeline	3.5%	1,013	544
Wind turbines, solar panels and other	4.4%	1,092	519
Power transmission[1]	2.1%	384	29
Land and right-of-way	4.3%	6	6
Under construction[1]	-	1,233	1,761
		3,728	2,859
Accumulated depreciation		(344)	(350)
		3,384	2,509
Sponsored Investments			
Pipeline	2.9%	8,979	6,890
Pumping equipment, buildings, tanks and other	3.2%	5,381	4,787
Wind turbines, solar panels and other	3.7%	2,243	1,544
Land and right-of-way	2.3%	755	642
Under construction	-	2,201	2,002
		19,559	15,865
Accumulated depreciation		(3,429)	(2,770)
		16,130	13,095
Corporate			
Other[1]	12.7%	84	76
Under construction[1]	-	36	12
		120	88
Accumulated depreciation		(42)	(37)
		78	51
		42,279	33,318

1 *Due to a change in organizational structure effective January 1, 2013, Property, plant and equipment of $313 million were reclassified from the Corporate segment to the Gas Pipelines and Energy Services segment for the year ended December 31, 2012.*

Depreciation expense for the year ended December 31, 2013 was $1,282 million (2012 - $1,174 million; 2011 - $1,089 million).

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Impairment

In December 2012, the Company recorded an impairment charge of $166 million ($105 million after-tax) related to certain of its Enbridge Offshore Pipelines (Offshore) assets, predominantly located within the Stingray and Garden Banks corridors in the Gulf of Mexico. The Company had been pursuing alternative uses for these assets; however, due to changing competitive conditions in the fourth quarter of 2012, the Company concluded that such alternatives were no longer likely to proceed. In addition, unique to these assets is their significant reliance on natural gas production from shallow water areas of the Gulf of Mexico which have been challenged by macro-economic factors including prevalence of onshore shale gas production, hurricane disruptions, additional regulation and the low natural gas commodity price environment.

The impairment charge was based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows, and was presented within Operating and administrative expense on the Consolidated Statements of Earnings. The charge was inclusive of $50 million related to abandonment costs which were reasonably determined given the expected timing and scope of certain asset retirements. A portion of the impairment charge was subsequently reclassified to discontinued operations as noted below.

Discontinued Operations

During the fourth quarter of 2013, Enbridge concluded it would seek to dispose of certain assets within the Stingray corridor and entered into negotiations with an unrelated third party. As a result, at December 31, 2013, the related assets and liabilities were classified as held for sale and were measured at the lower of their carrying amount and estimated fair value less cost to sell which did not result in a fair value adjustment. The results of operations including revenues of $26 million (2012 - $32 million, 2011 - $19 million) and related cash flows have been presented as discontinued operations for the year ended December 31, 2013, with the prior year comparative figures reclassified. These amounts are included in the Gas Pipelines, Processing and Energy Services segment. The Company expects to complete the sale in the first quarter of 2014.

11. VARIABLE INTEREST ENTITY

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta and is considered a VIE by virtue of its capital structure. The Company is the primary beneficiary of the Fund through its combined 67.3% (2012 - 67.7%; 2011 - 69.2%) economic interest, held indirectly through a common investment in ENF, a direct common trust unit investment in the Fund and a preferred unit investment in a wholly-owned subsidiary of the Fund. Enbridge also serves in the capacity of Manager of ENF, the Fund and its subsidiaries.

The summarized impact of the Company's interest in the Fund on earnings, cash flows and financial position is presented below. Earnings include the results of operations of certain assets acquired by the Fund from wholly-owned subsidiaries of Enbridge from the dates of acquisition of October 2011 and December 2012 *(Note 19)*. Earnings, cash flows and financial position information exclude the effect of intercompany transactions.

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Revenues	403	288	146
Operating and administrative expense	(126)	(83)	(66)
Depreciation and amortization	(130)	(87)	(47)
Income from equity investments	57	54	57
Interest expense	(91)	(68)	(32)
Income taxes	(27)	(35)	(21)
Earnings	86	69	37
Loss attributable to noncontrolling interest	24	12	9
Earnings attributable to Enbridge	110	81	46
Cash flows			
Cash provided by operating activities	260	200	137
Cash used in investing activities	(98)	(160)	(95)
Cash provided by/(used in) financing activities	(323)	1,495	381
Increase/(decrease) in cash and cash equivalents	(161)	1,535	423

December 31,	2013	2012
(millions of Canadian dollars)		
Current assets	84	224
Property, plant and equipment, net	2,317	2,390
Long-term investments	227	215
Deferred amounts and other assets	130	145
Current liabilities	(388)	(250)
Long-term debt	(1,364)	(1,864)
Other long-term liabilities	(26)	(22)
Deferred income taxes	(426)	(404)
Net assets before noncontrolling interests	554	434

12. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	2013	2012
(millions of Canadian dollars)			
Equity Investments			
Joint Ventures			
Liquids Pipelines			
Chicap Pipeline	43.8%	29	27
Mustang Pipeline	30.0%	23	21
Seaway Pipeline	50.0%	2,048	1,385
Gas Pipelines, Processing and Energy Services			
Offshore - various joint ventures	22.0% - 74.3%	401	391
Vector	60.0%	125	130
Alliance Pipeline US	50.0%	201	181
Aux Sable	42.7% - 50.0%	306	266
Other	33.3% - 70.0%	11	10
Sponsored Investments			
Alliance Pipeline Canada	50.0%	165	179
Texas Express Pipeline	35.0%	396	183
Other	50.0%	62	35
Other Equity Investments			
Corporate			
Noverco Common Shares	38.9%	-	-
Other	16.3% - 49.99%	56	55
Other Long-Term Investments			
Corporate			
Noverco Preferred Shares		287	246
Other		102	66
		4,212	3,175

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date which is comprised of $680 million (2012 - $636 million) in Goodwill and $517 million (2012 - $493 million) in amortizable assets.

JOINT VENTURES

Summarized combined financial information of the Company's interest in unconsolidated equity investments in joint ventures is as follows:

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Revenues	1,212	956	827
Commodity costs	(371)	(236)	(138)
Operating and administrative expense	(268)	(244)	(200)
Depreciation and amortization	(175)	(159)	(158)
Other income/(expense)	4	4	(3)
Interest expense	(74)	(81)	(87)
Earnings before income taxes	328	240	241

December 31,	2013	2012
(millions of Canadian dollars)		
Current assets	366	299
Property, plant and equipment, net	4,050	3,192
Deferred amounts and other assets	35	26
Intangible assets, net	75	74
Goodwill	680	639
Current liabilities	(395)	(333)
Long-term debt	(994)	(895)
Other long-term liabilities	(50)	(194)
Net assets	3,767	2,808

Alliance Pipeline

Certain assets of Alliance Pipeline Canada are pledged as collateral to Alliance Pipeline Canada lenders and to the lenders of Alliance Pipeline US. As well, certain assets of Alliance Pipeline US are pledged as collateral to Alliance Pipeline US lenders and to the lenders of Alliance Pipeline Canada.

OTHER EQUITY INVESTMENTS

Noverco

At December 31, 2013, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2012 - 38.9%; 2011 - 38.9%) of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a range of 4.3% to 4.4%.

At December 31, 2013, Noverco owned an approximate 3.9% (2012 - 6.0%; 2011 - 8.9%) reciprocal shareholding in common shares of Enbridge. The change in reciprocal shareholding compared with prior years reflected the sale of Enbridge common shares by Noverco in 2012 and 2013. Through secondary offerings, Noverco sold 22.5 million Enbridge common shares in 2012 and a further 15 million common shares in 2013. Enbridge's share of the net after-tax proceeds of $297 million and $248 million were received as dividends from Noverco in May 2012 and June 2013, respectively. The transactions were recognized as issuances of treasury stock on the Consolidated Statements of Changes in Equity and as an operating activity on the Consolidated Statements of Cash Flows.

As a result of Noverco's reciprocal shareholding in Enbridge common shares, the Company has an indirect pro-rata interest of 1.5% (2012 - 2.1%; 2011 - 3.5%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $86 million at December 31, 2013 (2012 - $126 million; 2011 - $187 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco.

13. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	2013	2012
(millions of Canadian dollars)		
Regulatory assets	1,172	1,123
Long-term portion of derivative assets *(Note 23)*	413	408
Affiliate long-term note receivable *(Note 28)*	185	182
Contractual receivables	356	303
Deferred financing costs	135	127
Other	401	318
	2,662	2,461

At December 31, 2013, deferred amounts of $307 million (2012 - $265 million) were subject to amortization and are presented net of accumulated amortization of $159 million (2012 - $123 million). Amortization expense for the year ended December 31, 2013 was $34 million (2012 - $25 million; 2011 - $20 million).

14. INTANGIBLE ASSETS

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	13.2%	**825**	**241**	**584**
Natural gas supply opportunities	3.7%	**311**	**65**	**246**
Power purchase agreements	4.0%	**87**	**7**	**80**
Transportation agreements	3.7%	**53**	**15**	**38**
Other	4.0%	**64**	**8**	**56**
		1,340	**336**	**1,004**

December 31, 2012	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	11.9%	622	180	442
Natural gas supply opportunities	3.8%	291	50	241
Power purchase agreements	4.7%	85	4	81
Transportation agreements	2.9%	50	13	37
Other	5.6%	20	4	16
		1,068	251	817

Total amortization expense for intangible assets was $82 million (2012 - $64 million; 2011 - $58 million) for the year ended December 31, 2013. The Company expects aggregate amortization expense for the years ending December 31, 2014 through 2018 of $93 million, $83 million, $73 million, $65 million and $57 million, respectively.

15. GOODWILL

	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Balance at January 1, 2012	48	-	30	362	-	440
Transfer of assets to the Fund	(29)	-	-	29	-	-
Foreign exchange and other	3	-	(17)	(7)	-	(21)
Balance at December 31, 2012	22	-	13	384	-	419
Foreign exchange and other	**1**	**-**	**1**	**24**	**-**	**26**
Balance at December 31, 2013	**23**	**-**	**14**	**408**	**-**	**445**

The Company did not recognize any goodwill impairments for the years ended December 31, 2013 and 2012.

16. ACCOUNTS PAYABLE AND OTHER

December 31,	**2013**	2012
(millions of Canadian dollars)		
Operating accrued liabilities	**3,577**	2,729
Trade payables	**300**	123
Construction payables	**1,188**	568
Current derivative liabilities *(Note 23)*	**837**	1,075
Contractor holdbacks	**211**	86
Taxes payable	**176**	206
Security deposits	**65**	69
Other	**310**	196
	6,664	5,052

17. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2013**	2012
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.2%	2024	**200**	200
Medium-term notes[1]	4.8%	2015-2043	**2,985**	2,435
Southern Lights project financing[2]	2.7%	2014	**1,480**	1,413
Commercial paper and credit facility draws			**266**	25
Other[3]			**11**	12
Gas Distribution				
Debentures	9.9%	2024	**85**	85
Medium-term notes	5.3%	2014-2050	**2,702**	2,295
Commercial paper and credit facility draws			**374**	590
Sponsored Investments				
Junior subordinated notes[4]	8.1%	2067	**425**	398
Medium-term notes	3.9%	2014-2023	**1,615**	1,615
Senior notes[5]	6.3%	2014-2040	**4,201**	4,129
Commercial paper and credit facility draws[6]			**717**	1,405
Corporate				
United States dollar term notes[7]	4.2%	2015-2023	**2,393**	1,094
Medium-term notes	4.6%	2015-2042	**4,518**	4,268
Commercial paper and credit facility draws[8]			**3,598**	1,488
Other[9]			**(28)**	(14)
Total debt			**25,542**	21,438
Current maturities			**(2,811)**	(652)
Short-term borrowings[10]			**(374)**	(583)
Long-term debt			**22,357**	20,203

1 *Included in medium-term notes is $100 million with a maturity date of 2112.*
2 *2013 - $352 million and US$1,061 million (2012 - $357 million and US$1,061 million).*
3 *Primarily capital lease obligations.*
4 *2013 - US$400 million (2012 - US$400 million).*
5 *2013 - US$3,950 million (2012 - US$4,150 million).*
6 *2013 - $41 million and US$635 million (2012 - $250 million and US$1,160 million).*
7 *2013 - US$2,250 million (2012 - US$1,100 million).*
8 *2013 - $2,476 million and US$1,055 million (2012 - $1,140 million and US$350 million).*
9 *Primarily debt discount.*
10 *Weighted average interest rate - 1.1% (2012 - 1.1%).*

For the years ending December 31, 2014 through 2018, debenture and term note maturities are $1,330 million, $931 million, $1,393 million, $952 million, $960 million, respectively, and $13,562 million thereafter. The Company's debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2014 through 2018 are $1,138 million, $1,088 million, $1,063 million, $988 million and $851 million, respectively. At December 31, 2013 and 2012, all debt is unsecured except for the Southern Lights project financing which is collateralized by the Southern Lights project assets of approximately $2,680 million (2012 - $2,565 million).

INTEREST EXPENSE

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Debentures and term notes	**1,123**	986	891
Commercial paper and credit facility draws	**34**	33	74
Southern Lights project financing	**40**	38	38
Capitalized	**(250)**	(216)	(75)
	947	841	928

CREDIT FACILITIES

	Maturity Dates[2]	December 31, 2013 Total Facilities	Draws[3]	Available	December 31, 2012 Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	300	266	34	300
Gas Distribution	2014-2019	713	382	331	712
Sponsored Investments	2015-2018	4,781	809	3,972	3,162
Corporate	2015-2018	11,805	3,651	8,154	9,108
		17,599	5,108	12,491	13,282
Southern Lights project financing[1]	2014-2015	1,570	1,498	72	1,484
Total credit facilities		19,169	6,606	12,563	14,766

1 *Total facilities inclusive of $63 million for debt service reserve letters of credit.*
2 *Total facilities include $35 million in demand facilities with no specified maturity date.*
3 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2014 to 2018.

Commercial paper and credit facility draws, net of short-term borrowings, of $4,580 million (2012 - $2,925 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

18. OTHER LONG-TERM LIABILITIES

December 31,	2013	2012
(millions of Canadian dollars)		
Future removal and site restoration liabilities *(Note 6)*	929	882
Derivative liabilities *(Note 23)*	1,395	763
Pension and OPEB liabilities *(Note 25)*	264	573
Other	350	323
	2,938	2,541

19. NONCONTROLLING INTERESTS

December 31,	2013	2012
(millions of Canadian dollars)		
EEP	2,810	2,636
Enbridge Energy Management, L.L.C. (EEM)	1,079	498
EGD preferred shares	100	100
Other	25	24
	4,014	3,258

Noncontrolling interests in EEP represented the 79.4% (2012 - 78.2%) interest in EEP held by public unitholders, as well as interests of third parties in subsidiaries of EEP, including Midcoast Energy Partners, L.P. (MEP). The increase in noncontrolling interests in EEP included contributions of $372 million (US$355 million) received from an initial public offering (IPO) of MEP. In May 2013, EEP formed MEP, which at the time was EEP's wholly owned subsidiary, and transferred approximately 39% of its ownership interest in EEP's natural gas and NGL midstream business to MEP. In November 2013, MEP completed the IPO whereby a total of 21.3 million MEP's Class A common units were issued (including 2.8 million Class A common units issued pursuant to the exercise of the underwriters' over-allotment option in December 2013) representing approximately 46% limited partner interest in MEP.

During the year ended December 31, 2013, EEP also distributed $463 million (2012 - $419 million; 2011 - $353 million) to its noncontrolling interest holders in line with EEP's objective to make quarterly distributions in an amount equal to its available cash, as defined in its partnership agreement and as approved by EEP's Board of Directors.

During the year ended December 31, 2012, EEP completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests from 77.0% to 78.2%.The listed share issuance during the year ended December 31, 2012 resulted in contributions of $382 million (2011 - $695 million) from noncontrolling interest holders.

Noncontrolling interests in EEM represented the 88.3% (2012 - 83.2%) of the listed shares of EEM not held by the Company. The increase in noncontrolling interests reflected the issuance of listed shares in 2013 in which the Company did not participate and which resulted in contributions of $523 million from noncontrolling interest holders.

The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The preferred shares have no fixed maturity date and have floating adjustable cash dividends that are payable at 80% of the prime rate. EGD may, at is option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2013, no preferred shares have been redeemed.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Balance at beginning of year	**1,000**	640	362
Loss	**(24)**	(12)	(9)
Other comprehensive income/(loss)			
Change in unrealized gains/(loss) on cash flow hedges, net of tax	**4**	(1)	(3)
Comprehensive loss	**(20)**	(13)	(12)
Distributions to unitholders	**(72)**	(49)	(33)
Contributions from unitholders	**92**	225	170
Redemption value adjustment	**53**	197	153
Balance at end of year	**1,053**	1,000	640

Redeemable noncontrolling interests in the Fund at December 31, 2013 represented 68.6% (2012 - 67.7%; 2011 - 64.6%) of interests in the Fund's trust units that are held by third parties. During the year ended December 31, 2013, the Fund completed a unit issuance in which the Company did not participate, resulting in an increase in the redeemable noncontrolling interests from 67.7% to 68.6%. This resulted in contributions of $92 million from redeemable noncontrolling interest holders.

In December 2012, the Fund acquired Greenwich, Amherstburg and Tilbury solar energy projects, Hardisty Caverns and Hardisty Contract Terminals from Enbridge and wholly-owned subsidiaries of Enbridge for proceeds of $1.2 billion. In October 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for $1.2 billion. In both cases, ordinary trust units were issued by the Fund to partially finance these acquisitions, resulting in an increase in interests held by third parties in 2012 and 2011 and contributions from noncontrolling unitholders of $225 million and $170 million, respectively.

Distributions to noncontrolling unitholders were made on a monthly basis for the years ended December 31, 2013, 2012 and 2011 in line with the Fund's objective of distributing a high proportion of its cash available for distribution, as approved by its Board of Trustees.

20. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

December 31,	2013 Number of Shares	2013 Amount	2012 Number of Shares	2012 Amount	2011 Number of Shares	2011 Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	805	4,732	781	3,969	770	3,683
Common Shares issued[1]	13	582	10	388	-	-
Dividend Reinvestment and Share Purchase Plan (DRIP)	8	361	8	297	7	229
Shares issued on exercise of stock options	5	69	6	78	4	57
Balance at end of year	831	5,744	805	4,732	781	3,969

1 *Gross proceeds - $600 million (2012 - $400 million); net issuance costs - $18 million (2012 - $12 million).*

PREFERENCE SHARES

December 31,	2013 Number of Shares	2013 Amount	2012 Number of Shares	2012 Amount	2011 Number of Shares	2011 Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference Shares, Series A	5	125	5	125	5	125
Preference Shares, Series B	20	500	20	500	20	500
Preference Shares, Series D	18	450	18	450	18	450
Preference Shares, Series F	20	500	20	500	-	-
Preference Shares, Series H	14	350	14	350	-	-
Preference Shares, Series J	8	199	8	199	-	-
Preference Shares, Series L	16	411	16	411	-	-
Preference Shares, Series N	18	450	18	450	-	-
Preference Shares, Series P	16	400	16	400	-	-
Preference Shares, Series R	16	400	16	400	-	-
Preference Shares, Series 1	16	411	-	-	-	-
Preference Shares, Series 3	24	600	-	-	-	-
Preference Shares, Series 5	8	206	-	-	-	-
Preference Shares, Series 7	10	250	-	-	-	-
Issuance costs		(111)		(78)		(19)
Balance at end of year		5,141		3,707		1,056

Characteristics of the preference shares are as follows:

(Canadian dollars unless otherwise stated)	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
Preference Shares, Series A	5.5%	$1.375	$25	-	-
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.0%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R	4.0%	$1.000	$25	June 1, 2019	Series S
Preference Shares, Series 1	4.0%	US$1.000	US$25	June 1, 2018	Series 2
Preference Shares, Series 3	4.0%	$1.000	$25	September 1, 2019	Series 4
Preference Shares, Series 5	4.4%	US$1.100	US$25	March 1, 2019	Series 6
Preference Shares, Series 7[5]	4.4%	$1.100	$25	March 1, 2019	Series 8

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend per year, as declared by the Board of Directors of the Company.*

2 *Preference Shares, Series A may be redeemed any time at the Company's option. For all other series of Preference Shares, the Company may at its option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

3 *The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on the Conversion Option Date and every fifth anniversary thereafter.*

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4) or 2.6% (Series 8)); or US$25 x (number of days in quarter/365) x (three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6)).*

5 *A cash dividend of $0.2381 per share will be payable on March 1, 2014 to Series 7 preference shareholders. The regular quarterly dividend of $0.275 per share will begin in the second quarter of 2014.*

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 15 million (2012 - 20 million; 2011 - 25 million), resulting from the Company's reciprocal investment in Noverco.

The treasury stock method is used to determine the dilutive impact of stock options. This method assumes any proceeds from the exercise of stock options would be used to purchase common shares at the average market price during the period.

December 31,	**2013**	2012	2011
(number of common shares in millions)			
Weighted average shares outstanding	**806**	772	751
Effect of dilutive options	**11**	13	10
Diluted weighted average shares outstanding	**817**	785	761

For the year ended December 31, 2013, 6,327,500 anti-dilutive stock options (2012 - 5,733,000; 2011 - 48,000) with a weighted average exercise price of $44.85 (2012 - $38.32; 2011 - $32.02) were excluded from the diluted earnings per share calculation.

STOCK SPLIT

Effective May 25, 2011, a two-for-one split of the common shares of the Company was completed. All references to the number of shares outstanding, earnings per common share, diluted earnings per common share, dividends per common share and outstanding option information have been retroactively restated to reflect the impact of the stock split.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN
Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN
The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

21. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PBSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 47 million have been issued to date. A further 52 million common shares have been reserved for issuance for the 2007 ISO and PBSO plans, of which seven million have been exercised and issued from treasury to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS
Key employees are granted ISO to purchase common shares at the market price on the grant date. ISO 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
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**27,368**	**25.69**		
Options granted	**6,369**	**44.85**		
Options exercised[1]	**(3,948)**	**20.10**		
Options cancelled or expired	**(187)**	**30.99**		
Options outstanding at end of year	**29,602**	**30.52**	**6.7**	**425**
Options vested at end of year[2]	**15,151**	**23.12**	**5.2**	**330**

1 *The total intrinsic value of ISO exercised during the year ended December 31, 2013 was $98 million (2012 - $130 million; 2011 - $68 million) and cash received on exercise was $24 million (2012 - $69 million; 2011 - $56 million).*

2 *The total fair value of options vested under the ISO Plan during the year ended December 31, 2013 was $22 million (2012 - $19 million; 2011 - $17 million).*

Weighted average assumptions used to determine the fair value of ISO granted 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 ISO was $27 million (2012 - $23 million; 2011 - $16 million). At December 31, 2013, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the ISO Plan was $37 million. The cost is expected to be fully recognized over a weighted average period of approximately three years.

PERFORMANCE BASED STOCK OPTIONS

PBSO are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSO were granted on August 15, 2007, February 19, 2008 and August 15, 2012 under the 2007 plan. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements were fulfilled evenly over a five-year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. 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 the Company'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
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	6,704	29.56		
Options exercised[1]	(2,331)	18.29		
Options outstanding at end of year	4,373	35.56	5.7	41
Options vested at end of year[2]	830	19.44	1.6	21

1 The total intrinsic value of PBSO exercised during the year ended December 31, 2013 was $62 million (2012 - $20 million; 2011 - $2 million) and cash received on exercise was $28 million (2012 - $12 million; 2011 - $3 million).

2 The total fair value of options vested under the PBSO Plan during the year ended December 31, 2013 was nil (2012 - $1 million; 2011 - $2 million).

Assumptions used to determine the fair value of PBSO granted using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	2012
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 recorded for the year ended December 31, 2013 for PBSO was $3 million (2012 - $2 million; 2011 - $2 million). At December 31, 2013, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PBSO Plan was $11 million. The cost is expected to be fully recognized over a weighted average period of approximately four years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for executives 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 the Company'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 the Company's performance fails to meet threshold performance levels, to a maximum of two if the Company performs within the highest range of its performance targets. The 2011, 2012 and 2013 grants derive the performance multiplier through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company'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
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**652**		
Units granted	**259**		
Units matured[1]	**(346)**		
Dividend reinvestment	**26**		
Units outstanding at end of year	**591**	**1.5**	**54**

1 *The total amount paid during the year ended December 31, 2013 for PSU was $48 million (2012 - $25 million; 2011 - $17 million).*

Compensation expense recorded for the year ended December 31, 2013 for PSU was $25 million (2012 - $49 million; 2011 - $42 million). As at December 31, 2013, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $26 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 the Company'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
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	1,819		
Units granted	920		
Units cancelled	(36)		
Units matured[1]	(953)		
Dividend reinvestment	78		
Units outstanding at end of year	1,828	1.5	84

1 *The total amount paid during the year ended December 31, 2013 for RSU was $41 million (2012 - $37 million; 2011 - $39 million).*

Compensation expense recorded for the year ended December 31, 2013 for RSU was $36 million (2012 - $32 million; 2011 - $31 million). As at December 31, 2013, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $46 million and is expected to be fully recognized over a weighted average period of approximately two years.

22. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in AOCI attributable to Enbridge common shareholders for the years ended December 31, 2013, 2012 and 2011, are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB	Total
(millions of Canadian dollars)						
Balance at January 1, 2013	(621)	474	(1,265)	(26)	(324)	(1,762)
Other comprehensive income/(loss) retained in AOCI	707	(111)	487	11	165	1,259
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	134	-	-	-	-	134
Commodity contracts[2]	(1)	-	-	-	-	(1)
Foreign exchange contracts[3]	(8)	-	-	-	-	(8)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	36	36
	832	(111)	487	11	201	1,420
Tax impact						
Income tax on amounts retained in AOCI	(176)	15	-	-	(51)	(212)
Income tax on amounts reclassified to earnings	(36)	-	-	-	(9)	(45)
	(212)	15	-	-	(60)	(257)
Balance at December 31, 2013	(1)	378	(778)	(15)	(183)	(599)

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB	Total
Balance at January 1, 2012	(476)	461	(1,167)	(28)	(286)	(1,496)
Other comprehensive income/(loss) retained in AOCI	(172)	16	(98)	7	(75)	(322)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	(17)	-	-	-	-	(17)
Commodity contracts[2]	(4)	-	-	-	-	(4)
Foreign exchange contracts[3]	1	-	-	-	-	1
Other contracts[4]	2	-	-	-	-	2
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	23	23
	(190)	16	(98)	7	(52)	(317)
Tax impact						
Income tax on amounts retained in AOCI	36	(3)	-	(5)	19	47
Income tax on amounts reclassified to earnings	9	-	-	-	(5)	4
	45	(3)	-	(5)	14	51
Balance at December 31, 2012	(621)	474	(1,265)	(26)	(324)	(1,762)

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB	Total
Balance at January 1, 2011	(66)	480	(1,245)	(11)	(142)	(984)
Other comprehensive income/(loss) retained in AOCI	(656)	(21)	78	(20)	(229)	(848)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	51	-	-	-	-	51
Commodity contracts[2]	43	-	-	-	-	43
Foreign exchange contracts[3]	1	-	-	-	-	1
Other contracts[4]	(2)	-	-	-	-	(2)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	29	29
	(563)	(21)	78	(20)	(200)	(726)
Tax impact						
Income tax on amounts retained in AOCI	161	2	-	3	64	230
Income tax on amounts reclassified to earnings	(8)	-	-	-	(8)	(16)
	153	2	-	3	56	214
Balance at December 31, 2011	(476)	461	(1,167)	(28)	(286)	(1,496)

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Commodity costs in the Consolidated Statements of Earnings.
3 Reported within Other income/(expense) in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
5 These components are included in the computation of net periodic pension costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

The Company's earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market price risk). 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 a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

The Company's earnings, cash flows and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues denominated in United States dollars and certain expenses denominated in Euros. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over a five-year forecast horizon. The Company may also hedge anticipated foreign currency denominated purchases or sales, foreign currency denominated debt, as well as certain equity investment balances and net investments in foreign denominated subsidiaries. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage variability in cash flows arising from its United States dollar investments and subsidiaries, and primarily non-qualifying derivative instruments to manage variability arising from certain revenues denominated in United States dollars.

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 hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2017 through execution of floating to fixed interest rate swaps with an average swap rate of 1.5%.

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 hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2018. A total of $10,419 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.8%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt which stays within its Board of Directors approved policy limit of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company uses primarily qualifying derivative instruments to manage interest rate risk.

Commodity Price Risk
The Company's earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted stock units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the 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 the counterparties in these particular circumstances. The following table also summarizes the maximum potential settlement in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

December 31, 2013	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment 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 *(Note 8)*						
Foreign exchange contracts	16	11	51	78	(26)	52
Interest rate contracts	171	-	12	183	(27)	156
Commodity contracts	4	-	114	118	(64)	54
Other contracts	2	-	4	6	-	6
	193	11	181	385	(117)	268
Deferred amounts and other assets *(Note 13)*						
Foreign exchange contracts	7	33	27	67	(62)	5
Interest rate contracts	249	-	1	250	(47)	203
Commodity contracts	9	-	86	95	(67)	28
Other contracts	1	-	-	1	-	1
	266	33	114	413	(176)	237
Accounts payable and other *(Note 16)*						
Foreign exchange contracts	(2)	(4)	(69)	(75)	26	(49)
Interest rate contracts	(387)	-	(16)	(403)	45	(358)
Commodity contracts	(14)	-	(345)	(359)	64	(295)
	(403)	(4)	(430)	(837)	135	(702)
Other long-term liabilities *(Note 18)*						
Foreign exchange contracts	(4)	(31)	(435)	(470)	62	(408)
Interest rate contracts	(68)	-	(1)	(69)	29	(40)
Commodity contracts	(2)	-	(854)	(856)	67	(789)
	(74)	(31)	(1,290)	(1,395)	158	(1,237)
Total net derivative asset/(liability)						
Foreign exchange contracts	17	9	(426)	(400)	-	(400)
Interest rate contracts	(35)	-	(4)	(39)	-	(39)
Commodity contracts	(3)	-	(999)	(1,002)	-	(1,002)
Other contracts	3	-	4	7	-	7
	(18)	9	(1,425)	(1,434)	-	(1,434)

December 31, 2012	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment 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 *(Note 8)*						
Foreign exchange contracts	4	16	210	230	(101)	129
Interest rate contracts	7	-	9	16	(9)	7
Commodity contracts	9	-	119	128	(28)	100
Other contracts	3	-	6	9	-	9
	23	16	344	383	(138)	245
Deferred amounts and other assets *(Note 13)*						
Foreign exchange contracts	11	79	225	315	(40)	275
Interest rate contracts	18	-	12	30	(25)	5
Commodity contracts	1	-	59	60	(32)	28
Other contracts	2	-	1	3	-	3
	32	79	297	408	(97)	311
Accounts payable and other *(Note 16)*						
Foreign exchange contracts	(5)	-	(100)	(105)	101	(4)
Interest rate contracts	(673)	-	-	(673)	9	(664)
Commodity contracts	(3)	-	(294)	(297)	28	(269)
	(681)	-	(394)	(1,075)	138	(937)
Other long-term liabilities *(Note 18)*						
Foreign exchange contracts	(41)	(5)	(23)	(69)	40	(29)
Interest rate contracts	(290)	-	(15)	(305)	25	(280)
Commodity contracts	(2)	-	(387)	(389)	32	(357)
	(333)	(5)	(425)	(763)	97	(666)
Total net derivative asset/(liability)						
Foreign exchange contracts	(31)	90	312	371	-	371
Interest rate contracts	(938)	-	6	(932)	-	(932)
Commodity contracts	5	-	(503)	(498)	-	(498)
Other contracts	5	-	7	12	-	12
	(959)	90	(178)	(1,047)	-	(1,047)

The following table summarizes the maturity and notional principal or quantity outstanding related to the Company's derivative instruments.

December 31, 2013	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	710	25	25	413	2	4
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,795	2,751	2,323	2,557	1,649	3,771
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	5	28	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	5,007	5,210	5,030	3,965	274	267
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	5,738	1,779	1,814	1,090	-	-
Equity contracts *(millions of Canadian dollars)*	40	41	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	17	(8)	10	11	46	-
Commodity contracts - crude oil *(millions of barrels)*	(34)	(29)	(23)	(18)	(9)	-
Commodity contracts - NGL *(millions of barrels)*	(10)	(2)	-	-	-	-
Commodity contracts - power *(megawatt hours (MWH))*	55	5	20	40	30	8

December 31, 2012	2013	2014	2015	2016	2017	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	558	468	25	25	413	6
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,088	2,402	2,751	2,323	2,557	158
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	6	-	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	3,644	3,591	3,455	3,157	2,841	171
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	4,590	3,055	1,760	1,142	-	-
Equity contracts *(millions of Canadian dollars)*	39	36	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	55	19	10	10	11	3
Commodity contracts - crude oil *(millions of barrels)*	37	38	29	23	18	9
Commodity contracts - NGL *(millions of barrels)*	1	2	-	-	-	-
Commodity contracts - power *(MWH)*	51	67	48	63	83	66

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income

The following table presents the effect of cash flow hedges and net investment 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			
Foreign exchange contracts	56	(12)	(22)
Interest rate contracts	814	(46)	(724)
Commodity contracts	(9)	52	72
Other contracts	(2)	(3)	6
Net investment hedges			
Foreign exchange contracts	(81)	1	(26)
	778	(8)	(694)
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*			
Foreign exchange contracts[1]	(8)	1	1
Interest rate contracts[2]	107	(1)	(10)
Commodity contracts[3]	1	(3)	(55)
Other contracts[4]	-	2	(2)
	100	(1)	(66)
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	51	23	11
Commodity contracts[3]	(3)	(3)	5
	48	20	16

1 *Reported within Other income/(expense) in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $135 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices 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 48 months at December 31, 2013.

Non-Qualifying Derivatives

The following table presents the unrealized gains and losses associated with changes in the fair value of the Company's non-qualifying derivatives.

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Foreign exchange contracts[1]	(738)	120	(179)
Interest rate contracts[2]	(10)	(2)	9
Commodity contracts[3]	(496)	(765)	280
Other contracts[4]	(3)	(2)	4
Total unrealized derivative fair value gains/(loss)	(1,247)	(649)	114

1 Reported within Transportation and other services revenues (2013 - $352 million loss; 2012 - $150 million gain; 2011 - $77 million loss) and Other income/(expense) (2013 - $386 million loss; 2012 - $30 million loss; 2011 - $102 million loss) in the Consolidated Statements of Earnings.

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

3 Reported within Transportation and other services revenues (2013 - $375 million loss; 2012 - $681 million loss; 2011 - $216 million gain), Commodity costs (2013 - $35 million loss; 2012 - $21 million loss; 2011 - $61 million gain) and Operating and administrative expense (2013 - $86 million loss; 2012 - $63 million loss; 2011 - $3 million gain) in the Consolidated Statements of Earnings.

4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States 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 approximately 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 *(Note 17)*.

CREDIT RISK

Entering into derivative financial instruments may 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.

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

December 31,	2013	2012
(millions of Canadian dollars)		
Canadian financial institutions	230	306
United States financial institutions	227	129
European financial institutions	192	244
Other[1]	97	128
	746	807

1 Other is comprised of commodity clearing house and physical natural gas and crude oil counterparties.

As at December 31, 2013, the Company had provided letters of credit totalling $81 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The

Company held $18 million of cash collateral on derivative asset exposures at December 31, 2013 and held no cash collateral at December 31, 2012.

Gross derivative balances have been presented without the effects of collateral posted. 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.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Gas Distribution, credit risk is mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has obtained additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

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 market value based on generally accepted valuation techniques or models and are supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations.

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 foreign exchange forward and cross currency swap contracts, interest rate swaps, physical forward commodity contracts, as well as commodity swaps and options for which observable inputs can be obtained.

The Company has also categorized the fair value of its held to maturity preferred share investment and long-term debt as Level 2. The fair value of the Company's held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. 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.

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. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. The Company does not have any other financial instruments categorized in 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 and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share price) 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.

Fair Value of Derivatives

The Company has categorized its derivative assets and liabilities measured at fair value as follows:

December 31, 2013	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	78	-	78
Interest rate contracts	-	183	-	183
Commodity contracts	6	42	70	118
Other contracts	-	6	-	6
	6	309	70	385
Long-term derivative assets				
Foreign exchange contracts	-	67	-	67
Interest rate contracts	-	250	-	250
Commodity contracts	-	72	23	95
Other contracts	-	1	-	1
	-	390	23	413
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(75)	-	(75)
Interest rate contracts	-	(403)	-	(403)
Commodity contracts	(9)	(248)	(102)	(359)
	(9)	(726)	(102)	(837)
Long-term derivative liabilities				
Foreign exchange contracts	-	(470)	-	(470)
Interest rate contracts	-	(69)	-	(69)
Commodity contracts	-	(701)	(155)	(856)
	-	(1,240)	(155)	(1,395)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(400)	-	(400)
Interest rate contracts	-	(39)	-	(39)
Commodity contracts	(3)	(835)	(164)	(1,002)
Other contracts	-	7	-	7
	(3)	(1,267)	(164)	(1,434)

December 31, 2012	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	230	-	230
Interest rate contracts	-	16	-	16
Commodity contracts	3	7	118	128
Other contracts	-	9	-	9
	3	262	118	383
Long-term derivative assets				
Foreign exchange contracts	-	315	-	315
Interest rate contracts	-	30	-	30
Commodity contracts	-	51	9	60
Other contracts	-	3	-	3
	-	399	9	408
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(105)	-	(105)
Interest rate contracts	-	(673)	-	(673)
Commodity contracts	(9)	(212)	(76)	(297)
	(9)	(990)	(76)	(1,075)
Long-term derivative liabilities				
Foreign exchange contracts	-	(69)	-	(69)
Interest rate contracts	-	(305)	-	(305)
Commodity contracts	-	(314)	(75)	(389)
	-	(688)	(75)	(763)
Total net financial asset/(liability)				
Foreign exchange contracts	-	371	-	371
Interest rate contracts	-	(932)	-	(932)
Commodity contracts	(6)	(468)	(24)	(498)
Other contracts	-	12	-	12
	(6)	(1,017)	(24)	(1,047)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

December 31, 2013	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	4	Forward gas price	3.64	5.18	4.37	\$/mmbtu[3]
Crude	1	Forward crude price	67.52	103.86	72.84	\$/barrel
NGL	(8)	Forward NGL price	1.00	2.26	1.53	\$/gallon
Power	(141)	Forward power price	43.50	67.67	57.62	\$/MWH
Commodity contracts - physical[1]						
Natural gas	(22)	Forward gas price	3.36	5.29	4.18	\$/mmbtu[3]
Crude	(10)	Forward crude price	64.73	113.19	92.15	\$/barrel
NGL	4	Forward NGL price	0.02	2.68	1.59	\$/gallon
Power	(1)	Forward power price	32.40	38.98	35.07	\$/MWH
Commodity options[2]						
Natural gas	2	Option volatility	25%	31%	28%	
NGL	7	Option volatility	22%	44%	31%	
	(164)					

1 *Financial and physical forward commodity contracts are valued using a market approach valuation technique.*
2 *Commodity options contracts are valued using an option model valuation technique.*
3 *One million British thermal units (mmbtu).*

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of the Company's Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices and, for option contracts, price volatility. Changes in forward commodity prices could result in significantly different fair values for the Company's Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally speaking, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of price volatility.

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

Year ended December 31,	**2013**	2012
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**(24)**	32
Total gains/(loss)		
Included in earnings[1]	**(100)**	(69)
Included in OCI	**-**	13
Settlements	**(40)**	-
Level 3 net derivative liability at end of period	**(164)**	(24)

1 *Reported within Transportation and other services revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels 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 prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totalled $103 million at December 31, 2013 (2012 - $66 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $287 million at December 31, 2013 (2012 - $246 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. At December 31, 2013, the fair value of this preferred share investment approximates its face value of $580 million (2012 - $580 million).

At December 31, 2013, the Company's long-term debt had a carrying value of $25,168 million (2012 - $20,855 million) and a fair value of $27,469 million (2012 - $24,809 million).

24. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Earnings before income taxes, discontinued operations and extraordinary loss	613	1,186	2,012
Canadian federal statutory income tax rate	15%	15%	16.5%
Expected federal taxes at statutory rate	92	178	332
Increase/(decrease) resulting from:			
Provincial and state income taxes	(1)	97	126
Foreign and other statutory rate differentials[1]	45	(69)	130
Effects of rate-regulated accounting	(55)	(38)	(15)
Foreign allowable interest deductions	(39)	(24)	(19)
Part VI.1 tax, net of federal Part I deduction[2]	23	19	1
Intercompany sale of investment[3]	-	33	59
Noncontrolling interests	26	(32)	(62)
Other[4]	32	7	(29)
Income taxes on earnings before discontinued operations and extraordinary loss	123	171	523
Effective income tax rate	20.0%	14.4%	26.0%

1 *The effective income tax rate for 2012 reflected significant losses relating to certain risk management activities in the Company's United States operations and the higher United States federal statutory rate over the Canadian federal statutory rate. The losses did not persist to the same extent in 2013.*

2 *Represents Part VI.1 tax on preference share dividend distributions, net of an allowed federal deduction. For 2013, this tax was presented net of an $11 million federal tax recovery related to changes to tax law enacted during the year.*

3 *In December 2012 and October 2011, Enbridge and certain wholly-owned subsidiaries of Enbridge sold certain assets to the Fund. As these transactions occurred between entities under common control of the Company, the intercompany gains realized as a result of these transfers were eliminated, although tax expense of $56 million and $98 million remained as a charge to earnings in 2012 and 2011, respectively, of which the federal tax component was $33 million and $59 million. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying entities; however, accounting recognition of such benefit is not permitted until such time as the entities are sold outside of the consolidated group.*

4 *Other for 2013 includes $55 million related to the federal component of the tax effect of adjustments related to prior periods.*

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 PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Earnings before income taxes, discontinued operations and extraordinary loss			
Canada	193	1,037	683
United States	132	(58)	1,196
Other	288	207	133
	613	1,186	2,012
Current income taxes			
Canada	(30)	130	194
United States	18	35	(30)
Other	4	3	(6)
	(8)	168	158
Deferred income taxes			
Canada	31	160	30
United States	100	(157)	335
	131	3	365
Income taxes on earnings before discontinued operations and extraordinary loss	123	171	523

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	(1,984)	(1,289)
Investments	(1,226)	(1,397)
Regulatory assets	(248)	(221)
Other	(115)	(144)
Total deferred income tax liabilities	(3,573)	(3,051)
Deferred income tax assets		
Financial instruments	487	380
Pension and OPEB plans	128	180
Loss carryforwards	129	161
Other	68	51
Total deferred income tax assets	812	772
Less valuation allowance	(28)	(27)
Total deferred income tax assets, net	784	745
Net deferred income tax liabilities	(2,789)	(2,306)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 8)*	120	167
Deferred income taxes	16	10
Total deferred income tax assets	136	177
Liabilities		
Deferred income taxes	(2,925)	(2,483)
Total deferred income tax liabilities	(2,925)	(2,483)
Net deferred income tax liabilities	(2,789)	(2,306)

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2013, the Company recognized the benefit of unused tax loss carryforwards of $322 million (2012 - $183 million) in Canada which start to expire in 2029 and beyond.

As at December 31, 2013, the Company recognized the benefit of unused tax loss carryforwards of $34 million (2012 - $222 million) in the United States which expire in 2032.

The Company has not provided for deferred income taxes on $573 million (2012 - $548 million) of foreign subsidiaries' undistributed earnings as at December 31, 2013 as such earnings are intended to be indefinitely reinvested in the operations of these foreign subsidiaries. Upon distribution of these earnings in the form of dividends or otherwise, the Company would be subject to income taxes in the United States. It is not practicable to determine the income tax liability that might be incurred if these earnings were to be distributed.

The Company and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Company is subject to potential examinations include the United States (federal and Texas) and Canada (federal, Alberta, Ontario and Quebec). The Company's 2006 and 2008 to 2013 taxation years are still open for audit in Canadian jurisdictions, whereas 2009 to 2013 taxation years are open for audit in United States jurisdictions. The Company is not currently under examination for income tax matters in any jurisdiction where it is subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	2013	2012
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	54	18
Gross increases for tax positions of current year	10	38
Gross increases/(decreases) for tax positions of prior years	(14)	3
Reduction for lapse of statute of limitations	(4)	(5)
Unrecognized tax benefits at end of year	46	54

The unrecognized tax benefits as at December 31, 2013, if recognized, would affect the Company's effective income tax rate. The gross increases for tax positions taken in the current year are in respect of the computation of Texas Margin Tax. The gross decreases for tax positions of prior years largely relates to filing positions that were based on substantively enacted legislation pertaining to Part VI.1 tax that became enacted in the second quarter of 2013.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of income taxes. Income tax expense for the year ended December 31, 2013 included a $5 million recovery (2012 - $1 million expense; 2011 - $1 million expense) of interest and penalties. The recovery of interest and penalties is substantially attributed to interest that was previously accrued on a filing position that is now statute-barred. As at December 31, 2013, interest and penalties of $5 million (2012 - $10 million) have been accrued.

25. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Canadian Plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2013 was used to determine the plan assets and accrued benefit obligation for the Canadian and United States 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, the mortality assumptions were revised for the Canadian Plans resulting in an increase to pension liabilities of $58 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 dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2012	December 31, 2013
Gas Distribution	September 1, 2013	September 1, 2016
United States Plan	January 1, 2013	January 1, 2014

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

OPEB primarily includes supplemental health and 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	1,879	1,686	261	243
Service cost	103	84	9	8
Interest cost	79	74	11	10
Employees' contributions	-	-	1	1
Actuarial (gains)/loss	(110)	106	(40)	14
Benefits paid	(75)	(64)	(7)	(8)
Effect of foreign exchange rate changes	19	(5)	6	(2)
Other	8	(2)	(1)	(5)
Benefit obligation at end of year	1,903	1,879	240	261
Change in plan assets				
Fair value of plan assets at beginning of year	1,500	1,355	62	54
Actual return on plan assets	200	117	8	5
Employer's contributions	155	97	12	13
Employees' contributions	-	-	1	1
Benefits paid	(75)	(64)	(7)	(8)
Effect of foreign exchange rate changes	13	(3)	5	(1)
Other	6	(2)	-	(2)
Fair value of plan assets at end of year[1]	1,799	1,500	81	62
Underfunded status at end of year	(104)	(379)	(159)	(199)
Presented as follows:				
Deferred amounts and other assets	6	-	-	-
Accounts payable and other	-	-	(5)	(5)
Other long-term liabilities *(Note 18)*	(110)	(379)	(154)	(194)
	(104)	(379)	(159)	(199)

1 *Assets of $27 million (2012 - $19 million) are held by the Company in trust accounts that back non-registered supplemental pension plans benefitting United States plan participants. Due to United States tax regulations, these assets are not restricted from creditors and therefore the Company is unable to include these balances in plan assets for accounting purposes. However, these assets are committed for the future settlement of non-registered supplemental pension plan obligations included in the underfunded status as at the end of the year.*

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%	4.2%	4.5%	4.9%	4.0%	4.4%
Average rate of salary increases	3.7%	3.7%	3.5%			

NET BENEFIT COSTS RECOGNIZED

Year ended December 31,	Pension 2013	Pension 2012	Pension 2011	OPEB 2013	OPEB 2012	OPEB 2011
(millions of Canadian dollars)						
Benefits earned during the year	**103**	84	61	**9**	8	6
Interest cost on projected benefit obligations	**79**	74	73	**11**	10	11
Expected return on plan assets	**(103)**	(93)	(92)	**(4)**	(3)	(3)
Amortization of prior service costs	**1**	2	2	**-**	-	1
Amortization of actuarial loss	**52**	51	25	**2**	2	1
Net defined benefit costs on an accrual basis	**132**	118	69	**18**	17	16
Defined contribution benefit costs	**4**	4	4	**-**	-	-
Net benefit cost recognized in the Consolidated Statements of Earnings	**136**	122	73	**18**	17	16
Amount recognized in OCI:						
Net actuarial (gains)/loss[1]	**(158)**	42	172	**(45)**	10	29
Net prior service cost/(credit)[2]	**-**	-	-	**2**	-	(1)
Total amount recognized in OCI	**(158)**	42	172	**(43)**	10	28
Total amount recognized in Comprehensive income	**(22)**	164	245	**(25)**	27	44

1 *Unamortized actuarial losses included in AOCI, before tax, were $246 million (2012 - $388 million) relating to the pension plans and $11 million (2012 - $60 million) relating to OPEB at December 31, 2013.*

2 *Unamortized prior service costs included in AOCI, before tax, were $6 million (2012 - $4 million) relating to OPEB at December 31, 2013.*

The Company estimates that approximately $12 million related to pension plans and $1 million related to OPEB at December 31, 2013 will be reclassified from AOCI into earnings in the next 12 months.

Regulatory adjustments are 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 6)*. 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.

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

Year ended December 31,	Pension 2013	Pension 2012	Pension 2011	OPEB 2013	OPEB 2012	OPEB 2011
Discount rate	**4.2%**	4.5%	5.6%	**4.0%**	4.4%	5.6%
Average rate of return on pension plan assets	**6.7%**	7.1%	7.3%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.7%**	3.5%	3.5%			

MEDICAL COST TRENDS

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

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	8.3%	4.5%	2029
Other Medical	4.5%	-	-
United States Plan	7.4%	4.5%	2030

A 1% increase in the assumed medical care trend rate would result in an increase of $30 million in the benefit obligation and an increase of $2 million in benefit and interest costs. A 1% decrease in the assumed medical care trend rate would result in a decrease of $25 million in the benefit obligation and a decrease of $2 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
Canadian Plans	**6.6%**	6.9%		
United States Plan	**7.2%**	7.3%	**6.0%**	6.0%

Target Mix for Plan Assets

	Canadian Plans		
	Liquids Pipelines Plan	Gas Distribution Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

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 58.0% (2012 - 59.1%) in equity securities, 31.0% (2012 - 32.4%) in fixed income securities and 11.0% (2012 - 8.5%) in other. The OPEB assets were invested 59.3% (2012 - 58.1%) in equity securities, 38.3% (2012 - 35.5%) in fixed income securities and 2.4% (2012 - 6.4%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $1 million asset (2012 - $15 million liability) and refundable tax assets of $85 million (2012 - $76 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								
Cash and cash equivalents	42	-	-	42	44	-	-	44
Fixed income securities								
Canadian government bonds	99	-	-	99	87	-	-	87
Corporate bonds and debentures	3	4	-	7	-	4	-	4
Canadian corporate bond index fund	216	-	-	216	196	-	-	196
Canadian government bond index fund	167	-	-	167	152	-	-	152
United States debt index fund	69	-	-	69	45	2	-	47
Equity								
Canadian equity securities	128	-	-	128	190	-	-	190
United States equity securities	32	-	-	32	24	-	-	24
Global equity securities	11	-	-	11	9	-	-	9
Canadian equity funds	216	-	-	216	64	39	-	103
United States equity funds	152	33	-	185	60	26	-	86
Global equity funds	310	111	-	421	255	159	-	414
Infrastructure[4]	-	-	50	50	-	-	61	61
Real estate[5]	-	-	76	76	-	-	24	24
Forward currency contracts	-	(6)	-	(6)	-	(2)	-	(2)
OPEB								
Cash and cash equivalents	2	-	-	2	4	-	-	4
Fixed income securities								
United States government and government agency bonds	31	-	-	31	22	-	-	22
Equity								
United States equity funds	24	-	-	24	17	19	-	36
Global equity funds	24	-	-	24	-	-	-	-

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 investments in Bentall Kennedy Prime Canadian Property Fund Ltd and AEW Core Property Trust are established through the use of valuation models.*

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

	2013	2012
(millions of Canadian dollars)		
Balance at beginning of year	85	68
Unrealized and realized gains	7	11
Purchases and settlements, net	34	6
Balance at end of year	126	85

Plan Contributions by the Company

Year ended December 31,	Pension 2013	Pension 2012	OPEB 2013	OPEB 2012
(millions of Canadian dollars)				
Total contributions	155	97	12	13
Contributions expected to be paid in 2014	152		11	

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	80	85	90	95	101	591

26. OTHER INCOME/(EXPENSE)

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Net foreign currency gains/(loss)	(272)	71	48
Allowance for equity funds used during construction	1	1	3
Interest income on affiliate loans	23	20	17
Interest income	4	7	3
Noverco preferred shares dividend income	40	42	30
Gain on disposition *(Note 7)*	18	-	-
OPEB recovery *(Note 6)*	-	89	-
Other	51	8	15
	(135)	238	116

27. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	2013	2012	2011
(millions of Canadian dollars)			
Accounts receivable and other	(789)	(122)	121
Accounts receivable from affiliates	(53)	43	(17)
Inventory	(315)	42	93
Deferred amounts and other assets	(25)	(380)	(322)
Accounts payable and other	832	(319)	421
Accounts payable to affiliates	46	(48)	41
Interest payable	25	15	7
Other long-term liabilities	(130)	109	57
	(409)	(660)	401

28. RELATED PARTY TRANSACTIONS

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

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements were $6 million for the year ended December 31, 2013 (2012 - $6 million; 2011 - $6 million).

Certain wholly-owned subsidiaries within Gas Distribution and Gas Pipelines, Processing and Energy Services have transportation commitments with several joint venture affiliates that are accounted for using the equity method. Total amounts charged for transportation services for the year ended December 31, 2013 were $222 million (2012 - $127 million; 2011 - $106 million).

Additionally, certain wholly-owned subsidiaries within Gas Pipelines, Processing and Energy Services made natural gas purchases of $99 million (2012 - $15 million; 2011 - nil) and sales of $10 million (2012 - $7 million; 2011 - $5 million) with several joint venture affiliates during the year ended December 31, 2013.

LONG-TERM NOTE RECEIVABLE FROM AFFILIATE

Amounts receivable from affiliates include a series of loans to Vector totalling $181 million (2012 - $178 million), included in Deferred amounts and other assets, which require quarterly interest payments at annual interest rates ranging from 3% to 8%.

29. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts that primarily relate to the purchase of services, pipe and other materials, as well as transportation, totalling $10,232 million which are expected to be paid within the next five years and $3,115 million in total for years thereafter.

Minimum future payments under operating leases are estimated at $817 million in aggregate. Estimated annual lease payments for the years ending December 31, 2014 through 2018 are $116 million, $111 million, $108 million, $98 million and $52 million, respectively, and $332 million thereafter. Total rental expense for operating leases, included in Operating and administrative expense, were $49 million, $31 million and $28 million for the years ended December 31, 2013, 2012 and 2011, respectively.

ENVIRONMENTAL LIABILITIES

As at December 31, 2013, the Company had $260 million (2012 - $107 million) included in current liabilities and $27 million (2012 - $18 million) included in Other long-term liabilities which have been accrued for costs incurred primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain liquids and natural gas assets and known fines or penalties.

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 20.6% (2012 - 21.8%; 2011 - 23.0%) combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Lakehead System Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP's Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,700 barrels. EEP received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012, followed by an amended CAO on August 1, 2012. Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA will again consider the status of the pipeline in light of infomation they acquire throughout 2014.

The total estimated cost for the Line 14 crude oil release remains at approximately US$10 million ($1 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenue and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge's comprehensive insurance policy, although it does not expect any recoveries to be significant.

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. In response to the release, a unified command structure was established under the jurisdiction of the Environmental Protection Agency (EPA), the Michigan Department of Natural Resources and Environment and other federal, state and local agencies.

As at December 31, 2013, EEP's total cost estimate for the Line 6B crude oil release was US$1,122 million ($181 million after-tax attributable to Enbridge) which is an increase of US$302 million ($44 million after-tax attributable to Enbridge) compared to the December 31, 2012 estimate. This total estimate is before insurance recoveries and excludes additional fines and penalties other than US$30 million discussed below. On March 14, 2013, EEP received an order from the EPA (the Order) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. The Order states the work must be completed by December 31, 2013. EEP has currently completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta. EEP is in the process of working with the EPA to ensure this work is completed as soon as reasonably possible, inclusive of obtaining the necessary state and local permitting that is required and considering weather conditions.

Of the US$302 million increase compared with December 31, 2012 related to the Line 6B crude oil release, US$280 million is primarily related to additional work required by the Order including further refinement and definition of the additional dredging scope per the Order and all associated environmental, permitting, waste removal and other related costs, as well as increased dredge activity in and around Morrow Lake and the delta area. The actual costs incurred may differ from the foregoing estimate as EEP completes the work plan with the EPA related to the Order and works with other regulatory agencies to assure its work plan complies with their requirements. Any such incremental costs will not be recovered under EEP's insurance policies as the costs for the incident at December 31, 2013 exceeded the limits of the Company's insurance coverage. The remaining increase of US$22 million reflected an estimate of the minimum amount of civil penalties EEP may be assessed under the Clean Water Act of the United States (Clean Water Act) in respect of the Line 6B crude oil release.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 2013. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been completed. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release that occurred in Romeoville, Illinois, which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

The total estimated cost for the Line 6A crude oil release remains at approximately US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews throughout the year. On May 1 of each year, EEP's insurance program is up for renewal and includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties.

The claims for the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP's remediation spending through December 31, 2013, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. For the years ended December 31, 2013 and 2012, EEP recognized US$42 million ($6 million after-tax attributable to Enbridge) and US$170 million ($24 million after-tax attributable to Enbridge), respectively, of insurance recoveries as reductions to Environmental costs in the Consolidated Statements of Earnings. As at December 31, 2013, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release, out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable. In March 2013, the Company filed a lawsuit against one insurer who is disputing recovery eligibility for Line 6B costs. While the Company believes outstanding claims are covered under the policy, there can be no assurance that the Company will prevail in this lawsuit.

Effective May 1, 2013, Enbridge renewed its comprehensive property and liability insurance programs, under which EEP is insured through April 30, 2014, with a current liability aggregate limit of US$685 million, including sudden and accidental pollution liability. In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among the Enbridge entities on an equitable basis based on an insurance allocation agreement EEP has entered into with Enbridge and another Enbridge subsidiary.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Lines 6A and 6B crude oil releases. Approximately 30 actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material.

As at December 31, 2013, included in EEP's estimated costs related to the Line 6B crude oil release is US$30 million in fines and penalties. Of this amount, US$3.7 million related to civil penalties assessed by PHMSA that EEP paid during the third quarter of 2012. The total also included an amount of US$22 million related to civil penalties EEP expects to be required to pay under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$22 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief, if any, that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Discussions with governmental agencies regarding fines and penalties are ongoing.

One claim related to Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order.

TAX MATTERS

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

OTHER LEGAL AND REGULATORY PROCEEDINGS
The Company and its subsidiaries are 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.

30. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

The Company has also agreed to indemnify the Fund for certain liabilities relating to environmental matters arising from operations prior to the transfer of certain crude oil storage assets to the Fund in 2012.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, changes in laws, valuation differences, litigation and contingent liabilities. The Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties under these agreements; however, historically, the Company has not made any significant payments under indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. The indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.