ENBRIDGE INC
Form 6-K
May 02, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

Pursuant to Rule 13a-16 or 15d-16 of

the Securities Exchange Act of 1934

Dated May 2, 2012

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

Canada	**None**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

3000, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrants telephone number, including area code)

Indicate by check mark whether the Registrant files or will file annual reports under cover of Form 20-F or Form 40-F.

Form 20-F	Form 40-F	**P**

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1):

Yes	No	**P**

Indicate by check mark if the Registrant is submitting the Form 6-K in paper as permitted by regulation S-T Rule 101(b)(7):

Yes	No	**P**

Indicate by check mark whether the Registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes No **P**

If Yes is marked, indicate below the file number assigned to the Registrant in connection with Rule 12g3-2(b):

N/A

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 33-77022) AND FORM F-10 (FILE NO. 333-170200) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- U.S. GAAP Consolidated Financial Statements

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date: May 2, 2012

By: /s/ Alison T. Love
Alison T. Love
Vice President and Corporate Secretary

ENBRIDGE INC.

U.S. GAAP CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2011

Independent Auditor s Report

To the Directors of Enbridge Inc.

We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2011 and December 31, 2010 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, 2011, 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 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 entity s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity s internal control. An audit also includes evaluating the appropriateness of accounting 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.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2011 and December 31, 2010 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2011 in accordance with accounting principles generally accepted in the United States of America.

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Other matter

Enbridge Inc. has prepared another set of consolidated financial statements for the years ended December 31, 2011 and December 31, 2010 in accordance with Canadian generally accepted accounting principles. We have issued an integrated audit report on those consolidated financial statements and on the internal control over financial reporting as at December 31, 2011 to the shareholders of Enbridge Inc. dated February 21, 2012.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada

May 2, 2012

U.S. GAAP CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**20,611**	15,863	12,242
Gas distribution sales	**1,903**	1,812	2,186
Transportation and other services	**4,467**	3,775	3,274
	26,981	21,450	17,702
Expenses			
Commodity costs	**19,864**	15,276	11,551
Gas distribution costs	**1,209**	1,179	1,586
Operating and administrative	**2,281**	2,032	2,058
Depreciation and amortization	**1,112**	1,017	897
Environmental costs, net of recoveries *(Note 28)*	**(116)**	619	3
	24,350	20,123	16,095
	2,631	1,327	1,607
Income from equity investments *(Note 11)*	**210**	228	232
Other income *(Note 25)*	**117**	318	681
Interest expense *(Note 16)*	**(928)**	(865)	(751)
Gain on sale of investments *(Note 6)*	**-**	-	365
	2,030	1,008	2,134
Income taxes *(Note 23)*	**(526)**	(227)	(312)
Earnings from continuing operations	**1,504**	781	1,822
Loss from discontinued operations, net of tax *(Note 6)*	**-**	-	(70)
Earnings before extraordinary item	**1,504**	781	1,752
Extraordinary item, net of tax *(Note 30)*	**(262)**	-	-
Earnings	**1,242**	781	1,752
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(409)**	170	(234)
Earnings attributable to Enbridge Inc.	**833**	951	1,518
Preference share dividends	**(13)**	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	**820**	944	1,511
Earnings attributable to Enbridge Inc. common shareholders			
Earnings from continuing operations	**1,082**	944	1,530
Loss from discontinued operations, net of tax	**-**	-	(19)
Extraordinary item, net of tax *(Note 30)*	**(262)**	-	-
	820	944	1,511
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 19)*			
Continuing operations	**1.44**	1.27	2.10
Discontinued operations	-	-	(0.03)
Extraordinary item	**(0.35)**	-	-
	1.09	1.27	2.07
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 19)*			
Continuing operations	**1.42**	1.26	2.09
Discontinued operations	-	-	(0.03)
Extraordinary item	**(0.34)**	-	-
	1.08	1.26	2.06

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

U.S. GAAP CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings	**1,242**	781	1,752
Other comprehensive income/(loss)			
Change in unrealized loss on cash flow hedges, net of tax	**(582)**	(156)	(143)
Change in unrealized gain/(loss) on net investment hedges, net of tax	**(19)**	51	151
Other comprehensive income/(loss) from equity investees, net of tax	**(17)**	4	(6)
Reclassification to earnings of realized cash flow hedges, net of tax	**14**	(15)	123
Reclassification to earnings of unrealized cash flow hedges, net of tax *(Notes 6 and 22)*	**12**	(3)	(20)
Overfunded/(underfunded) pension adjustment, net of tax	**(144)**	(38)	13
Change in foreign currency translation adjustment	**151**	(376)	(1,207)
Other comprehensive loss	**(585)**	(533)	(1,089)
Comprehensive income	**657**	248	663
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(329)**	331	288
Comprehensive income attributable to Enbridge Inc.	**328**	579	951
Preferred share dividends	**(13)**	(7)	(7)
Comprehensive income attributable to Enbridge Inc. common shareholders	**315**	572	944

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

U.S. GAAP CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	2011	2010	2009
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 19)*			
Balance at beginning of year	**125**	125	125
Preference shares issued	**931**	-	-
Balance at end of year	**1,056**	125	125
Common shares *(Note 19)*			
Balance at beginning of year	**3,683**	3,379	3,194
Common shares issued	**-**	-	4
Dividend reinvestment and share purchase plan	**229**	224	143
Shares issued on exercise of stock options	**57**	80	38
Balance at end of year	**3,969**	3,683	3,379
Additional paid-in capital			
Balance at beginning of year	**131**	90	74
Stock-based compensation	**18**	13	19
Options exercised	**(7)**	(8)	(3)
Dilution gains	**100**	36	-
Balance at end of year	**242**	131	90
Retained earnings			
Balance at beginning of year	**3,993**	3,828	2,917
Earnings attributable to Enbridge Inc. common shareholders	**820**	944	1,511
Common share dividends declared	**(759)**	(648)	(555)
Dividends paid to reciprocal shareholder	**25**	19	17
Redemption value adjustment attributable to redeemable noncontrolling interests *(Note 18)*	**(153)**	(150)	(62)
Balance at end of year	**3,926**	3,993	3,828
Accumulated other comprehensive loss *(Note 21)*			
Balance at beginning of year	**(1,027)**	(654)	(88)
Other comprehensive loss attributable to Enbridge Inc. common shareholders	**(505)**	(373)	(566)
Balance at end of year	**(1,532)**	(1,027)	(654)
Reciprocal shareholding *(Note 11)*			
Balance at beginning of year	**(154)**	(154)	(154)
Acquisition of equity investment	**(33)**	-	-
Balance at end of year	**(187)**	(154)	(154)
Total Enbridge Inc. shareholders equity	**7,474**	6,751	6,614
Noncontrolling interests			
Balance at beginning of year	**2,424**	2,740	3,334
Earnings/(loss) attributable to noncontrolling interests	**416**	(182)	218
Other comprehensive income/(loss) attributable to noncontrolling interests			
Change in unrealized loss on cash flow hedges, net of tax	**(84)**	(12)	(95)
Change in foreign currency translation adjustment	**66**	(121)	(453)
Reclassification to earnings of realized cash flow hedges, net of tax	**(63)**	(13)	28
Reclassification to earnings of unrealized cash flow hedges, net of tax	**4**	(2)	-
Other comprehensive loss attributable to noncontrolling interests	**(77)**	(148)	(520)
Comprehensive income/(loss)	**339**	(330)	(302)
Distributions	**(355)**	(318)	(296)
Contributions *(Note 18)*	**735**	358	-
Dilution gain	**22**	15	-
Acquisitions *(Notes 6 and 18)*	**(27)**	(41)	-
Other	**3**	-	4
Balance at end of year	**3,141**	2,424	2,740
Total equity	**10,615**	9,175	9,354
Dividends paid per common share	**0.98**	0.85	0.74

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

U.S. GAAP CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Operating activities			
Earnings	**1,242**	781	1,752
Depreciation and amortization	**1,112**	1,017	897
Unrealized gains on derivative instruments, net	**(73)**	-	(176)
Allowance for equity funds used during construction	**(3)**	(96)	(148)
Cash distributions in excess of equity earnings	**125**	102	86
Regulatory asset write-off *(Note 30)*	**262**	-	-
Gain on sale of investments *(Note 6)*	**-**	-	(365)
Gain on acquisition *(Note 6)*	**-**	(22)	-
Deferred income taxes *(Note 23)*	**368**	203	229
Asset impairment losses *(Note 6)*	**11**	11	81
Other	**14**	9	(79)
Changes in regulatory assets and liabilities	**28**	29	(22)
Changes in environmental liabilities, net of recoveries *(Note 28)*	**(118)**	267	2
Changes in operating assets and liabilities *(Note 26)*	**403**	(424)	316
	3,371	1,877	2,573
Investing activities			
Additions to property, plant and equipment	**(3,452)**	(3,030)	(4,505)
Government grant	**145**	-	-
Additions to intangible assets	**(154)**	(56)	(87)
Changes in construction payable	**(19)**	60	(120)
Acquisitions, net of cash acquired *(Note 6 and 18)*	**(33)**	(850)	(28)
Long-term investments	**(1,571)**	(58)	(50)
Affiliate loans, net	**7**	14	(12)
Proceeds on sale of investments and net assets *(Note 6)*	**-**	23	696
Settlement of hedges *(Note 6)*	**-**	-	6
Changes in restricted cash	**(2)**	(5)	16
	(5,079)	(3,902)	(4,084)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**224**	(165)	(393)
Net change in commercial paper and credit facility draws	**(630)**	(212)	1,421
Net change in Southern Lights project financing	**(62)**	14	343
Debenture and term note issues	**1,604**	3,220	1,500
Debenture and term note repayments	**(234)**	(631)	(1,099)
Contributions from/(distributions to) noncontrolling interests, net	**518**	121	(299)
Contributions from/(distributions to) redeemable noncontrolling interests, net	**175**	(23)	(23)
Common shares issued	**46**	66	36
Preference shares issued	**926**	-	-
Preference share dividends	**(7)**	(7)	(7)
Common share dividends	**(530)**	(426)	(414)
	2,030	1,957	1,065
Effect of translation of foreign denominated cash and cash equivalents	**25**	(12)	(31)
Increase/(decrease) in cash and cash equivalents	**347**	(80)	(477)
Cash and cash equivalents at beginning of year	**376**	456	933
Cash and cash equivalents at end of year	**723**	376	456

Supplementary cash flow information			
Income taxes (received)/paid	**(28)**	115	211
Interest paid	**955**	871	819

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

U.S. GAAP CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2011**	2010
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**723**	376
Restricted cash	**17**	15
Accounts receivable and other *(Note 7)*	**4,011**	3,623
Accounts receivable from affiliates	**55**	38
Inventory *(Note 8)*	**823**	916
	5,629	4,968
Property, plant and equipment, net *(Note 9)*	**28,941**	26,355
Long-term investments *(Note 11)*	**3,160**	1,729
Deferred amounts and other assets *(Note 12)*	**2,667**	2,464
Intangible assets, net *(Note 13)*	**711**	585
Goodwill *(Note 14)*	**440**	431
Deferred income taxes *(Note 23)*	**29**	20
	41,577	36,552
Liabilities and equity		
Current liabilities		
Bank indebtedness	**102**	100
Short-term borrowings *(Note 16)*	**548**	326
Accounts payable and other *(Note 15)*	**4,764**	3,703
Accounts payable to affiliates	**48**	7
Interest payable	**185**	176
Environmental liabilities *(Note 28)*	**175**	226
Current maturities of long-term debt *(Note 16)*	**354**	185
	6,176	4,723
Long-term debt *(Note 16)*	**19,251**	18,403
Other long-term liabilities *(Note 17)*	**2,323**	1,642
Deferred income taxes *(Note 23)*	**2,572**	2,247
	30,322	27,015
Commitments and contingencies *(Note 28)*		
Redeemable noncontrolling interests *(Note 18)*	**640**	362
Equity		
Share capital *(Note 19)*		
Preference shares	**1,056**	125
Common shares (781 outstanding at December 31, 2011 (2010 - 770))	**3,969**	3,683
Additional paid-in capital	**242**	131
Retained earnings	**3,926**	3,993
Accumulated other comprehensive loss *(Note 21)*	**(1,532)**	(1,027)
Reciprocal shareholding *(Note 11)*	**(187)**	(154)
Total Enbridge Inc. shareholders equity	**7,474**	6,751
Noncontrolling interests *(Note 18)*	**3,141**	2,424
	10,615	9,175
	41,577	36,552

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

NOTES TO THE U.S. GAAP

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 operating 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 the Canadian Mainline, Regional Oil Sands System, Southern Lights Pipeline, Spearhead Pipeline, Seaway Crude Pipeline (Seaway Pipeline) interest and other feeder pipelines.

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 and processing facilities, green energy projects, Canadian midstream businesses, the Company s energy services businesses and international activities.

Investments in natural gas pipelines include the Company s interests in the United States portion of Alliance Pipeline (Alliance Pipeline US), the Vector Pipeline 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, an interest in the development of Cabin Gas Plant in northeastern British Columbia, and processing facilities connected to the Gulf of Mexico System. The energy services businesses manage the Company s volume commitments on Alliance and Vector Pipelines, as well as perform natural gas, NGL and crude oil storage, transport and supply management services, as principal and agent.

SPONSORED INVESTMENTS

Sponsored Investments includes the Company s 23.0% ownership interest in Enbridge Energy Partners, L.P. (EEP), Enbridge s 66.7% investment in the United States segment of the Alberta Clipper Project through EEP and Enbridge Energy, Limited Partnership (EELP) and an overall 69.2% economic interest in Enbridge Income Fund (the Fund), held both directly, and indirectly through Enbridge Income Fund Holdings Inc. (ENF). Enbridge 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 and transports, gathers, processes and markets natural gas and NGLs. The primary operations of the Fund include a crude oil and liquids pipeline and gathering system, a 50% interest in the Canadian portion of Alliance Pipeline (Alliance Pipeline Canada) and interests in renewable power generation projects.

CORPORATE

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Enbridge prepared and filed consolidated financial statements for the year ended December 31, 2011 in accordance with Part V Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook with a reconciliation to U.S. GAAP in conformity with Item 18 of Form 20-F under United States securities regulations. These U.S. GAAP consolidated financial statements for the year ended December 31, 2011 have been prepared on a voluntary basis. As a United States Security and Exchange Commission registrant, Enbridge is permitted by Canadian Securities regulation to prepare its financial statements in accordance with U.S. GAAP and will commence reporting using U.S. GAAP as its primary basis of accounting in 2012.

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 preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 13)*; measurement of goodwill *(Note 14)*; valuation of share based compensation *(Note 20)*; fair value of financial instruments *(Note 22)*; income taxes *(Note 23)*; retirement and postretirement benefits *(Note 24)*; commitments and contingencies *(Note* 28*);* and fair value of asset retirement obligations (AROs). 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.

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 Energy Resources Conservation Board in Alberta, 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.

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.

Certain regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Entities not subject to rate regulation write off the net book value of the retired asset and include any resulting gain or loss in earnings.

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 and the amount of revenue can be reliably measured. 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.

For the rate-regulated portion of the Company s main Canadian crude oil pipeline system, revenue was recognized in a manner that is consistent with the underlying agreements as approved by the regulator. Effective July 1, 2011, 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 July 1, 2011, the Company discontinued the application of rate-regulated accounting for its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis, with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenue is 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.

For the natural gas and marketing businesses within Sponsored Investments, there is one month of estimated revenue and cost of gas included in the Consolidated Statements of Earnings based on the best available volume and price data for natural gas delivered and received.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange 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 revenue, Commodity costs, Operating and administrative expense, Other income and Interest expense.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage 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 and cash flow 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 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 (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, 2011 or 2010.

Net Investment Hedges

The Company uses net investment hedges to manage 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 statement 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.

Balance Sheet Offset

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

Transaction Costs

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

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.

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. Dividends received from these financial assets are recognized in earnings when the right to receive payment is established.

NONCONTROLLING INTERESTS

Noncontrolling interests represent the outstanding ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and VIEs. The portion of the 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 Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interest is 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. For the Company s regulated operations, a deferred income tax liability is recognized with a corresponding regulatory asset. 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 whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period that they arise.

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 when there is a disposal of all 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, in accordance with specific customer agreements, as to withdrawal or usage 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

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

INVENTORY

Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage 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, inventory is recorded to Commodity costs in the Consolidated Statement 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.

The Company uses the group method of depreciation for all property, plant and equipment, except for the non rate-regulated assets in Canada and the United States, which are depreciated on a single asset basis. Depreciation is provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. Under the group method, upon the disposition of property, plant and equipment, the net book value less net proceeds is typically charged to accumulated depreciation and no gain or loss on disposal is recognized. However, when a separately identifiable group of assets, such as a stand-alone pipeline system, is sold, a gain or loss is recognized in the Consolidated Statements of Earnings for the difference between the cash received and the net book value of the assets sold.

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; direct financing lease receivable; as well as deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt.

INTANGIBLE ASSETS

Intangible assets consist primarily of 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. Potential impairment is identified when 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 assets and liabilities of the reporting unit.

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

AROs 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. AROs 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 AROs 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 estimate of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates which are determined using either the Citigroup Pension Discount Curve (United States Plan) or the discount rate curve developed by the Canadian Institute of Actuaries (Canadian Plans). Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Amortization of 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 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 other postretirement benefits (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 are recognized as Deferred amounts and other assets or Other long-term liabilities on the Consolidated Statements of Financial Position. A plan s funded status is measured as the difference between the fair value of plan assets and the plan s accrued 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 operations of the Company recover pension and OPEB expense based on amounts paid in accordance with the methodology accepted by the regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory asset has been recorded reflecting the Company s ability to incorporate this amount in future rates. In the absence of rate regulation, these balances would not be recorded and pension costs would be charged to earnings based on the accrual basis of accounting. No regulatory asset has been recorded for the difference between net periodic OPEB expense and the amount considered for rate-making purposes.

STOCK-BASED COMPENSATION

Incentive Stock Options (ISOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value 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 (PBSOs) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated by the Bloomberg barrier option valuation model and is recognized on a straight-line basis 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 (PSUs) and Restricted Stock Units (RSUs) are cash settled awards for which the related liability is remeasured each reporting period. PSUs vest at the completion of a three-year term and RSUs vest at the completion of a 35-month term. During the vesting term, an 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 Other long-term liabilities. The value of the PSUs 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. 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. 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 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

FUTURE ACCOUNTING POLICY CHANGES

Fair Value Measurement

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, which revises the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the FASB s joint project with the International Accounting Standards Board. Under the revised standard, the Company will be required to provide additional disclosures about fair value measurements, including information about the unobservable inputs and assumptions used in Level 3 fair value measurements, a description of the valuation methodologies used in Level 3 fair value measurements, and the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. This accounting update is effective for the first reporting period beginning after December 15, 2011.

Statement of Comprehensive Income

In June 2011, the FASB issued ASU 2011-05, which updates the existing guidance on comprehensive income under U.S. GAAP, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement does not affect the Company s presentation of comprehensive income, and will not have an impact on the Company s consolidated financial statements. This accounting update is effective for the first reporting period beginning after December 15, 2011.

Goodwill Impairment

In September 2011, the FASB issued ASU 2011-08, which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity will not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. This accounting update will be effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011.

Balance Sheet Offsetting

In December 2011, the FASB issued ASU 2011-11, which provides enhanced disclosures on the effect or potential effect of netting arrangements on an entity s financial position. The adoption of the pronouncement affects financial statement disclosures only and 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 on or after January 1, 2013.

4. SEGMENTED INFORMATION

Year ended December 31, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**1,942**	**2,444**	**13,599**	**8,996**	**-**	**26,981**
Commodity and gas distribution costs	**-**	**(1,210)**	**(13,051)**	**(6,812)**	**-**	**(21,073)**
Operating and administrative	**(752)**	**(508)**	**(138)**	**(847)**	**(36)**	**(2,281)**
Depreciation and amortization	**(322)**	**(320)**	**(75)**	**(383)**	**(12)**	**(1,112)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**116**	**-**	**116**
	868	**406**	**335**	**1,070**	**(48)**	**2,631**
Income/(loss) from equity investments	**5**	**-**	**153**	**57**	**(5)**	**210**
Other income/(expense)	**31**	**(12)**	**40**	**68**	**(10)**	**117**
Interest expense	**(256)**	**(166)**	**(56)**	**(350)**	**(100)**	**(928)**
Income taxes recovery/(expense)	**(140)**	**(54)**	**(166)**	**(171)**	**5**	**(526)**
Earnings/(loss) from continuing operations	**508**	**174**	**306**	**674**	**(158)**	**1,504**
Extraordinary item, net of tax	**-**	**(262)**	**-**	**-**	**-**	**(262)**
Earnings	**508**	**(88)**	**306**	**674**	**(158)**	**1,242**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(3)**	**-**	**(1)**	**(405)**	**-**	**(409)**
Preference share dividends	**-**	**-**	**-**	**-**	**(13)**	**(13)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**505**	**(88)**	**305**	**269**	**(171)**	**820**
Additions to property, plant and equipment1	**902**	**483**	**850**	**1,187**	**33**	**3,455**
Total assets	**12,470**	**7,189**	**4,468**	**13,453**	**3,997**	**41,577**

Year ended December 31, 2010	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,627	2,414	9,604	7,805	-	21,450
Commodity and gas distribution costs	-	(1,179)	(9,386)	(5,890)	-	(16,455)
Operating and administrative	(579)	(508)	(100)	(807)	(38)	(2,032)
Depreciation and amortization	(303)	(310)	(55)	(339)	(10)	(1,017)
Environmental costs	-	-	-	(619)	-	(619)
	745	417	63	150	(48)	1,327
Income from equity investments	9	-	151	59	9	228
Other income/(expense)	139	(17)	28	51	117	318
Interest expense	(224)	(179)	(51)	(295)	(116)	(865)
Income taxes recovery/(expense)	(136)	(66)	(61)	(44)	80	(227)
Earnings/(loss)	533	155	130	(79)	42	781
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(2)	(5)	-	177	-	170
Preference share dividends	-	-	-	-	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	531	150	130	98	35	944
Additions to property, plant and equipment1	741	387	1,114	884	-	3,126
Total assets	11,593	7,377	4,966	11,033	1,583	36,552

Year ended December 31, 2009	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,257	2,828	7,024	6,588	5	17,702
Commodity and gas distribution costs	-	(1,586)	(6,900)	(4,651)	-	(13,137)
Operating and administrative	(526)	(511)	(97)	(893)	(31)	(2,058)
Depreciation and amortization	(223)	(298)	(45)	(323)	(8)	(897)
Environmental costs	-	-	-	(3)	-	(3)
	508	433	(18)	718	(34)	1,607
Income from equity investments	20	-	140	61	11	232
Other income/(expense) and gain on sale of investments	165	(12)	353	25	515	1,046
Interest expense	(145)	(187)	(35)	(262)	(122)	(751)
Income taxes expense	(102)	(59)	(44)	(104)	(3)	(312)
Earnings from continuing operations	446	175	396	438	367	1,822
Loss from discontinued operations, net of tax	-	-	-	(70)	-	(70)
Earnings	446	175	396	368	367	1,752
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(2)	(6)	-	(225)	(1)	(234)
Preference share dividends	-	-	-	-	(7)	(7)
Earnings attributable to Enbridge Inc. common shareholders	444	169	396	143	359	1,511
Additions to property, plant and equipment1	2,678	326	230	1,409	10	4,653

1 Includes allowance for equity funds used during construction (AEDC).

The measurement basis for preparation of segmented information is consistent with the significant accounting policies described in Note 2.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Canada	**12,025**	9,315	7,410
United States	**14,956**	12,135	10,292
	26,981	21,450	17,702

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

Property, Plant and Equipment

December 31,	**2011**	2010
(millions of Canadian dollars)		
Canada	**16,557**	15,015
United States	**12,384**	11,340
	28,941	26,355

5. 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

The Canadian Mainline includes the Canadian portion of the mainline system. The primary business activities of the Canadian Mainline are subject to regulation by the NEB. Prior to July 1, 2011, the incentive tolling settlement (ITS) defined the methodology for calculation of tolls and the revenue requirement 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. Surcharges were also determined for a number of system expansion components and were added to the base toll determined for the core system.

Effective July 1, 2011, Canadian Mainline earnings (excluding Lines 8 and 9) were governed by the CTS. The CTS covers local tolls to be charged for service on the Canadian Mainline and supersedes all existing toll agreements on the Canadian Mainline during the ten year term of the CTS. While the CTS is based on previous tolling settlements and cost of service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment and the Company discontinued the application of rate-regulated accounting on a prospective basis commencing July 1, 2011.

The regulatory asset of approximately $470 million related to deferred income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of deferred income taxes incurred subsequent to the discontinuance of rate-regulated accounting, and, as such, regulatory assets related to deferred income taxes will continue to be recognized as incurred. The regulatory asset of approximately $70 million related to tolling deferrals recorded at the date of discontinuance is being recovered through a toll surcharge over a period of two years.

Southern Lights

The United States portion of the Southern Lights Pipeline is regulated by the FERC and the Canadian portion of the pipeline is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to 15-year 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. EGD s rates are based on a revenue per customer cap incentive regulation methodology that expires in December 2012, which adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions.

EGD s after-tax rate of return on common equity embedded in rates was 8.39% for the years ended December 31, 2011, 2010 and 2009 based on a 36% deemed common equity component of capital for regulatory purposes for each of those years.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick (EGNB) is regulated by the EUB and an application for rate adjustments is filed annually for EUB approval. EGNB s after-tax ROE for the year ended December 31, 2011 was 10.90% (2010 - 13.00%; 2009 - 13.00%) based on equity which is capped at 45%.

Due to amendments in the rate setting methodology enacted by the Government of New Brunswick in a final rates and tariffs regulation published in April 2012, EGNB no longer meets the criteria for the continuation of rate regulated accounting. As a result, the EGNB regulatory deferral has been written off as at December 31, 2011 as described in Note 30, Subsequent event.

FINANCIAL STATEMENT EFFECTS

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

December 31,	**2011**	2010	Estimated Settlement Period (years)
(millions of Canadian dollars)			
Regulatory assets/(liabilities)			
Liquids Pipelines			
Deferred income taxes[1]	**527**	479	-
Tolling deferrals[2]	**14**	132	1
Deferred transportation revenue[3]	**84**	32	29
Gas Distribution			
Deferred income taxes[1]	**170**	211	-
EGNB regulatory deferral[4]	**-**	171	-
Future removal and site restoration reserves[5]	**(836)**	(773)	-
Purchased gas variance[6]	**-**	(144)	1
Pension plans[7]	**108**	(58)	-
Sponsored Investments			
Deferred income taxes[1]	**83**	94	-

1 The asset represents the regulatory offset to deferred income tax liabilities to the extent that deferred income taxes are expected to be included in regulator-approved future rates and recovered from or refunded to future customers. The recovery period depends on future temporary differences.

2 Tolls for regulated pipelines under a cost of service methodology are established each year based on capacity and the allowed revenue requirement. Where actual volumes shipped on the pipeline result in an under or over collection of the annual revenue requirement, a regulatory asset or liability is recognized and incorporated into tolls in the subsequent year or in accordance with the related agreement.

3 Deferred transportation revenue is related to the cumulative difference between U.S. GAAP depreciation expense for Southern Lights and the negotiated depreciation rates included in the regulated transportation tolls. The Company expects to recover this difference after 2020 when depreciation rates in the transportation agreements are expected to exceed U.S. GAAP depreciation rates.

4 At December 31, 2010, a regulatory deferral account captures the cumulative difference between EGNB s distribution revenues and its cost of service revenue requirement. Due to a change in regulation enacted by the Government of New Brunswick in April 2012, the EGNB regulatory deferral has been written off at December 31, 2011 as EGNB no longer meets the criteria for rate regulated accounting. See Note 30, Subsequent event.

5 The future removal and site restoration reserves balance results from amounts collected from customers by certain of the Company s 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.

6 Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to customers in the following year.

7 The pension plan balance represents the regulatory offset to the pension plan liability to the extent that the amounts are to be collected from customers in future rates. The settlement period for this balance is not determinable. EGD continues to record and recover pension expenditures through rates on a cash basis.

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, 2011, cumulative costs relating to this consulting contract of $133 million (2010 - $124 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.

6. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

Seaway Crude Pipeline Company

On December 20, 2011, Enbridge acquired 50% of the outstanding common units in Seaway Pipeline, a partnership engaged in the crude oil pipeline business in Texas, for cash consideration of $1.2 billion (US$1.2 billion). The Company s investment in Seaway Pipeline is accounted for as a joint venture using the equity method *(Note 11)* within the Liquids Pipeline segment.

December 20,	**2011**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	**5**
Property, plant and equipment	**536**
Goodwill	**638**
Current liabilities	**(4)**
	1,175
Purchase Price:	
Cash (net of $9 million cash acquired)	**1,175**

A net loss of $1 million related to transaction costs was recognized in Earnings for the year ended December 31, 2011. Had the acquisition occurred on January 1, 2011, an unaudited proforma net loss of $2 million, including $1 million of transaction costs, would have been recognized as earnings. The entire amount of acquired goodwill is expected to be tax deductible for United States income tax purposes.

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.

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 revenue from Tonbridge was recognized in 2011 as the transmission line is not yet in service. A net loss of $1 million was recognized in income for the period from October 13, 2011 to December 31, 2011 related to operating and administrative expenses. An unaudited proforma net loss of $38 million, including $6 million of transaction costs, would have been recognized in income in 2011 had the acquisition occurred on January 1, 2011.

Elk City Natural Gas Gathering and Processing System

On September 16, 2010, the Company acquired a 100% ownership interest in entities that comprise the Elk City Natural Gas Gathering and Processing System (Elk City System) for $705 million (US$686 million). The results of operations of Elk City System have been included within the Sponsored Investments segment from the date of acquisition.

September 16,	2010
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Current assets	4
Property, plant and equipment, net	503
Intangible assets[1]	194
Other assets	5
Other long-term liabilities	(1)
	705
Purchase price:	
Cash	705

1 Intangible assets acquired are natural gas supply opportunities, which are being amortized on a straight line basis over the weighted average estimated useful life of the underlying reserves at the time of acquisition, which approximate 25 to 30 years.

Other Acquisitions

In August 2010, the Company acquired an additional 20% interest in Olympic Pipe Line Company (Olympic), a refined products pipeline, for $12 million, increasing its ownership interest to 85%. As the Company now controls the entity, it has consolidated its interest in Olympic. Prior to August 9, 2010, the entity was accounted for as a joint venture using the equity method.

In June 2010, the Company acquired the remaining 50% interest in Hardisty Caverns Limited Partnership (Hardisty Caverns), an oil storage facility, for $52 million, increasing its ownership interest to 100%. The original equity interest and noncontrolling interest were re-measured to fair value on the date control was obtained and a $22 million gain was recorded in Other income *(Note 25)* for the year ended December 31,

2010. As the Company now controls the entity, it has consolidated its interest in Hardisty Caverns. Prior to June 16, 2010, the entity was accounted for as a joint venture using the equity method.

During the year ended December 31, 2010, the Company acquired the remaining 27.5% of EGNB limited partnership units held by third parties for $52 million, increasing its partnership interest to 100%.

Other acquisitions during 2010 totaled $29 million (US$27 million) and are included within the Sponsored Investments segment.

During the year ended December 31, 2009, the Company purchased the additional 50% interest in Starfish Pipeline Company, LLC (Starfish Pipeline) for $28 million (US$27 million), increasing its ownership percentage to 100%. As the Company established control over the entity effective December 31, 2009, it has consolidated its interest in Starfish Pipeline from that date forward. Prior to December 31, 2009, the entity was accounted for as a joint venture using the equity method.

Proforma consolidated revenues and earnings that give effect to all other Company s 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.

DISPOSITIONS
Gain on Sale of Investments

December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
NetThruPut (NTP)	**-**	-	29
Oleoducto Central S.A. (OCENSA)	**-**	-	336
	-	-	365

NTP

On May 1, 2009, the Company sold its investment in NTP, an internet-based exchange facility for physical crude oil products, for proceeds of $32 million. Earnings generated by the NTP investment for the year ended December 31, 2009 were $1 million and are included in the Corporate operating segment.

OCENSA

On March 17, 2009, the Company sold its investment in OCENSA, a crude oil pipeline in Colombia, for proceeds of $512 million (US$402 million). Earnings and cash flows from operating activities generated by this investment for the year ended December 31, 2009 were $7 million. Earnings from the OCENSA investment were included in the Gas Pipelines, Processing and Energy Services operating segment. As a result of the sale of OCENSA, the Company reclassified $20 million of after-tax gains on unrealized cash flow hedges from OCI to earnings in the year ended December 31, 2009.

DISCONTINUED OPERATIONS

On November 1, 2009, EEP sold non-core natural gas pipeline assets for cash proceeds of $161 million (US$151 million), excluding any subsequent settlement for working capital as provided in the sale agreement. The loss from discontinued operations, net of tax, of $70 million for the year ended December 31, 2009, resulted from an impairment charge of $70 million. The areas in which the natural gas pipeline assets operated were not strategic to the ongoing operations of EEP s core natural gas pipeline assets.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Unbilled revenues	**2,210**	2,092
Trade receivables	**802**	849
Taxes receivable	**157**	205
Regulatory assets	**42**	170
Short-term portion of derivative assets *(Note 22)*	**486**	207
Prepaid expenses and deposits	**54**	44
Current deferred income taxes *(Note 23)*	**108**	2
Dividends receivable	**30**	11
Other	**180**	108
Allowance for doubtful accounts	**(58)**	(65)
	4,011	3,623

8. INVENTORY

December 31,	**2011**	2010
(millions of Canadian dollars)		
Natural gas	**566**	655
Other commodities	**257**	261
	823	916

Commodity costs on the Consolidated Statements of Earnings included non-cash charges of $9 million, $9 million and $4 million for the years ended December 31, 2011, 2010 and 2009, respectively, to reduce the cost basis of inventory to market value.

9. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2011	2010
(millions of Canadian dollars)			
Liquids Pipelines			
Pipeline	**2.8%**	**7,455**	7,275
Pumping equipment, buildings, tanks and other	**3.5%**	**4,982**	4,603
Land and right-of-way	**3.0%**	**230**	232
Under construction	**-**	**1,089**	712
		13,756	12,822
Accumulated depreciation		**(3,161)**	(2,817)
		10,595	10,005
Gas Distribution			
Gas mains, services and other	**4.0%**	**6,846**	6,605
Land and right-of-way	**2.5%**	**79**	68
Under construction	**-**	**137**	103
		7,062	6,776
Accumulated depreciation		**(1,419)**	(1,287)
		5,643	5,489
Gas Pipelines, Processing and Energy Services			
Pipeline	**3.6%**	**568**	513
Wind turbines, solar panels and other[1]	**4.9%**	**781**	1,207
Land and right-of-way	**3.6%**	**7**	19
Under construction	**-**	**512**	620
		1,868	2,359
Accumulated depreciation		**(213)**	(223)
		1,655	2,136
Sponsored Investments			
Pipeline	**2.5%**	**6,600**	6,116
Pumping equipment, buildings, tanks and other	**3.3%**	**3,792**	3,406
Wind turbines, solar panels and other[1]	**3.4%**	**1,074**	-
Land and right-of-way	**2.5%**	**611**	544
Under construction	**-**	**913**	417
		12,990	10,483
Accumulated depreciation		**(2,213)**	(1,805)
		10,777	8,678
Corporate			
Other	**2.9%**	**270**	67
Under construction	**-**	**31**	-
		301	67
Accumulated depreciation		**(30)**	(20)
		271	47
		28,941	26,355

1 In October 2011, Enbridge Pipelines Inc. (EPI) sold three renewable energy assets to the Fund. As a result, at December 31, 2011, $1,074 million of property, plant and equipment was reclassified from Gas Pipelines, Processing and Energy Services to Sponsored Investments. The December 31, 2010 balance of $1,103 million has not been reclassified for presentation purposes.

Depreciation expense for the year ended December 31, 2011 was $1,089 million (2010 - $987 million; 2009 - $853 million).

10. 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 69% (2010 - 72%) 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 the renewable energy assets transferred from Enbridge subsequent to transfer in October 2011. Earnings, cash flows and financial position information exclude the effect of intercompany transactions.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Revenues	**146**	89	92
Operating and administrative expense	**(66)**	(52)	(48)
Depreciation and amortization	**(47)**	(19)	(16)
Interest expense	**(32)**	(13)	(12)
Income from equity investments	**60**	60	62
Income taxes	**(21)**	(17)	(21)
Earnings	**40**	48	57
(Earnings)/loss attributable to noncontrolling interest	**7**	(11)	(16)
Earnings attributable to Enbridge Inc.	**47**	37	41
Cash flows			
Cash provided by operating activities	**140**	29	52
Cash used in investing activities	**(98)**	(107)	(20)
Cash provided by/(used in) financing activities	**381**	85	(35)
Increase/(decrease) in cash and cash equivalents	**423**	7	(3)

December 31,	**2011**	2010
(millions of Canadian dollars)		
Current assets	**109**	31
Property, plant and equipment, net	**1,349**	253
Long-term investments	**343**	357
Other assets	**125**	111
Current liabilities	**(90)**	(55)
Long-term debt	**(675)**	(420)
Other long-term liabilities	**(36)**	(20)
Deferred income taxes	**(403)**	(233)
Net assets before non-controlling interest	**722**	24

11. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2011**	2010
(millions of Canadian dollars)			
Equity Investments			
Joint Ventures			
Liquids Pipelines			
Chicap Pipeline	43.8%	**27**	27
Mustang Pipeline	30.0%	**27**	26
Woodland Pipeline	50.0%	**79**	23
Seaway Pipeline *(Note 6)*	50.0%	**1,186**	-
Texas Express Pipeline	35.0%	**11**	-
Gas Pipelines, Processing and Energy Services			
Enbridge Offshore Pipelines - various joint ventures	22.0%-74.3%	**420**	433
Vector Pipeline	60.0%	**160**	152
Alliance Pipeline US	50.0%	**293**	318
Aux Sable[1]	42.7%-50.0%	**217**	86
Other	33.3%-70.0%	**21**	27
Sponsored Investments			
Alliance Pipeline Canada	50.0%	**296**	316
Other	33.0%-50.0%	**47**	52
Other Equity Investments			
Corporate			
Noverco Common Shares	38.9%	**-**	14
Other	5.0%-20.0%	**34**	13
Other Long-Term Investments			
Corporate			
Noverco Preferred Shares		**285**	181
Value Creation Inc.		**29**	29
Fuel Cell Energy Ltd.		**11**	25
Other		**17**	7
		3,160	1,729

1 In July 2011, the Company, through its affiliate Aux Sable, acquired a 42.7% interest in the Palermo Conditioning Plant and the Prairie Rose Pipeline for $76 million.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investee s assets at the purchase date which is comprised of $651 million (2010 - $13 million) in goodwill and $30 million (2010 - $31 million) in amortizable assets.

JOINT VENTURES

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

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Revenues	**804**	771	784
Commodity costs	**(138)**	(92)	(75)
Operating and administrative expense	**(200)**	(203)	(226)
Depreciation and amortization	**(158)**	(158)	(166)
Other income/(expense)	**(3)**	(1)	11
Interest expense	**(87)**	(96)	(113)
Earnings before income taxes	**218**	221	215

December 31,	**2011**	2010
(millions of Canadian dollars)		
Current assets	**231**	172
Property, plant and equipment, net	**2,952**	2,339
Deferred amounts and other assets	**273**	278
Goodwill	**651**	13
Intangible assets	**87**	83
Current liabilities	**(239)**	(151)
Long-term debt	**(926)**	(1,035)
Other long-term liabilities	**(245)**	(239)
Net assets	**2,784**	1,460

EQUITY INVESTMENTS

Noverco

During the year ended December 31, 2011, the Company invested $144 million in cash and $255 million in a dividend received from Noverco to increase its common share investment from 32.1% to 38.9%. In addition, the Company received $399 million of preferred shares which are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus 4.40%. There has been no change in the accounting for the Company s common or preferred share investments in Noverco as a result of the restructuring. The Company s interest in Noverco continues to be accounted for as a long-term investment and is included in the Corporate segment.

The Company adjusted its preferred share investments in Noverco, which are entitled to cumulative preferred dividends based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.34% to 4.40%, to $285 million at December 31, 2011 due to the restructuring of Noverco in 2011. At December 31, 2011, the fair value of these held to maturity investments approximate their face value of $580 million (2010 - $181 million).

The Company also adjusted its equity investment in Noverco common shares to nil at December 31, 2011 (2010 - $14 million) due to the restructuring with an offsetting adjustment to the carrying value of the preferred share investments. Noverco owns an approximate 8.9% (2010 - 9.0%) reciprocal shareholding in the shares of the Company. As a result, the Company has an indirect pro-rata interest of 3.5% (2010 - 2.9%) in its own shares. Both the equity investment in Noverco and shareholders equity have been reduced by the reciprocal shareholding of $187 million at December 31, 2011 (2010 - $154 million; 2009 - $154 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. In 2011, the Company recorded equity investment loss of $6 million (2010 - $6 million of earnings; 2009 - $10 million of earnings) related to its common share interest in Noverco.

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.

12. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory assets	**1,000**	1,050
Long-term portion of derivative assets *(Note 22)*	**562**	467
Affiliate long-term note receivable *(Note 27)*	**194**	197
Contractual receivables	**288**	277
Direct financing lease	**167**	176
Deferred financing costs	**132**	93
Pension asset *(Note 24)*	**-**	58
Other	**324**	146
	2,667	2,464

At December 31, 2011, deferred amounts of $255 million (2010 - $227 million) were subject to amortization and are presented net of accumulated amortization of $106 million (2010 - $82 million). Amortization expense for the year ended December 31, 2011 was $20 million (2010 - $20 million; 2009 - $22 million).

13. INTANGIBLE ASSETS

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.7%	**471**	**155**	**316**
Natural gas supply opportunities	3.6%	**296**	**39**	**257**
Power purchase agreements	4.6%	**78**	**2**	**76**
Transportation agreements	2.9%	**53**	**10**	**43**
Other	6.0%	**27**	**8**	**19**
		925	**214**	**711**

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.6%	395	134	261

Natural gas supply opportunities	3.6%	289	28	261
Power purchase agreements	2.9%	24	1	23
Transportation agreements	4.0%	28	7	21
Other	6.4%	25	6	19
		761	176	585

Total amortization expense for intangible assets was $58 million (2010 - $52 million; 2009 - $41 million) for the year ended December 31, 2011. The Company expects aggregate amortization expense for the years ending December 31, 2012 through 2016 of $55 million, $50 million, $45 million, $40 million and $36 million, respectively.

14. GOODWILL

(millions of Canadian dollars)	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Balance at December 31, 2009	-	-	31	373	-	404
Business acquisition	29	-	-	-	-	29
Reclassification	18	-	-	-	-	18
Foreign exchange and other	-	-	(2)	(18)	-	(20)
Balance at December 31, 2010	47	-	29	355	-	431
Foreign exchange and other	**1**	-	**1**	**7**	**-**	**9**
Balance at December 31, 2011	**48**	-	**30**	**362**	**-**	**440**

In 2010, the Company recognized $17 million of goodwill on the acquisition of the remaining 50% interest in Hardisty. A revaluation of the original 50% interest in Hardisty upon acquisition resulted in an additional $12 million of goodwill.

As a result of the acquisition of an additional 20% interest in Olympic during 2010, the Company began consolidating its interest in Olympic. As a result of consolidating Olympic, $18 million of goodwill previously presented as part of the equity investment, has been reclassified to Goodwill.

The Company did not recognize any goodwill impairments for the years ended December 31, 2011 and 2010.

15. ACCOUNTS PAYABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating accrued liabilities	**2,758**	2,363
Trade payables	**176**	285
Construction payables	**327**	310
Current derivative liabilities *(Note 22)*	**880**	217
Contractor holdbacks	**46**	128
Taxes payable	**339**	201
Security deposits	**81**	75
Current deferred income taxes *(Note 23)*	**11**	47
Other	**146**	77
	4,764	3,703

16. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2011**	2010
(millions of Canadian dollars)				
Liquids Pipelines				
Debentures	8.20%	2024	**200**	200
Medium-term notes	5.05%	2012-2040	**2,435**	2,435
Southern Lights project financing[1]	2.52%	2013-2014	**1,449**	1,488
Commercial paper and credit facility draws			**26**	26
Other[2]			**13**	15
Gas Distribution				
Debentures	9.85%	2024	**85**	235
Medium-term notes	5.51%	2014-2050	**2,295**	2,195
Commercial paper and credit facility draws			**556**	334
Sponsored Investments				
First mortgage notes[3]	9.15%	2011	**-**	31
Junior subordinated notes[4]	8.05%	2067	**406**	397
Medium-term notes	4.72%	2012-2020	**415**	290
Senior notes[5]	6.23%	2012-2040	**4,322**	3,481
Commercial paper and credit facility draws[6]			**540**	1,010
Corporate				
U.S. dollar term notes[7]	5.48%	2014-2017	**1,119**	1,094
Medium-term notes	4.74%	2013-2040	**3,518**	2,918
Commercial paper and credit facility draws[8]			**2,785**	2,776
Other[9]			**(11)**	(11)
Total debt			**20,153**	18,914
Current maturities			**(354)**	(185)
Short-term borrowings [10]			**(548)**	(326)
Long-term debt			**19,251**	18,403

1 2011 $360 million and US$1,071 million (2010 - $388 million and US$1,106 million).

2 Primarily capital lease obligations.

3 2011 nil (2010 US$31 million).

4 2011 US$400 million (2010 US$400 million).

5 2011 US$4,250 million (2010 US$3,500 million).

6 2011 $260 million and US$275 million (2010 - $130 million and US$885 million).

7 2011 US$1,100 million (2010 US$1,100 million).

8 2011 $1,655 million and US$1,111 million (2010 - $2,515 million and US$265 million).

9 Primarily debt discount.

10 Weighted average interest rate 1.07% (2010 1.14%).

For the years ending December 31, 2012 through 2016, debenture and term note maturities are $352 million, $653 million, $1,100 million, $915 million, $1,005 million, respectively and $10,770 million thereafter. The Company s debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2012 through 2016 are $859 million, $826 million, $799 million, $748 million and $723 million, respectively. All debt is unsecured except for the first mortgage notes which were collateralized by a first mortgage lien on property, plant and equipment of the subsidiary, EELP. The liens were released when the notes reached maturity in 2011.

In February 2012, the Company issued $300 million and $200 million medium term notes with maturities of 2019 and 2022, respectively.

INTEREST EXPENSE

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Debentures and term notes	**891**	835	760
Commercial paper and credit facility draws	**74**	66	74
Southern Lights project financing	**38**	37	45
Capitalized	**(75)**	(73)	(128)
	928	865	751

CREDIT FACILITIES

December 31, 2011	Maturity Dates[2]	Total Facilities	Credit Facility Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	**2013**	**300**	**26**	**274**
Gas Distribution	**2012-2013**	**717**	**556**	**161**
Sponsored Investments	**2013-2016**	**2,534**	**725**	**1,809**
Corporate	**2012-2016**	**5,653**	**2,832**	**2,821**
		9,204	**4,139**	**5,065**
Southern Lights project financing[1]	**2013-2014**	**1,576**	**1,466**	**110**
Total credit facilities		**10,780**	**5,605**	**5,175**

1 *Total facilities inclusive of $61 million for debt service reserve letters of credit.*

2 *Total facilities include $30 million in demand facilities with no 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 0.18% 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 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,359 million (2010 - $3,820 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

17. OTHER LONG-TERM LIABILITIES

December 31,	**2011**	2010

(millions of Canadian dollars)		
Future removal and site restoration liabilities *(Note 5)*	**836**	773
Regulatory liabilities	**-**	77
Pension and OPEB liabilities *(Note 24)*	**515**	216
Derivative liabilities *(Note 22)*	**557**	201
Direct financing lease	**107**	114
Other	**308**	261
	2,323	1,642

18. NONCONTROLLING INTERESTS

December 31, *(millions of Canadian dollars)*	**2011**	2010
EEP	**2,528**	1,881
Enbridge Energy Management, L.L.C. (EEM)	**464**	384
EGD preferred shares	**100**	100
Talbot Windfarm, LP (Talbot)	**-**	26
Greenwich Windfarm, LP (Greenwich)	**26**	12
Other	**23**	21
	3,141	2,424

Noncontrolling interests in EEP represent the 77.0% interest in EEP not owned by the Company. During the year ended December 31, 2011, EEP completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests from 74.5% to 77.0%.

Noncontrolling interests in EEM represent the 83.2% of the listed shares of EEM not held by the Company. During the year ended December 31, 2011, EEM completed a listed share issuance, in which the Company did not participate, resulting in an increase in the noncontrolling interests from 82.8% to 83.2%.

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 fixed yield rate on these preferred shares was 4.93% per annum until July 1, 2009, after which floating adjustable cumulative cash dividends are payable at 80% of the prime rate. The preferred shares have no fixed maturity date. 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, 2011, no preferred shares have been redeemed.

Noncontrolling interests in both Talbot and Greenwich represent 10% of partnership units held by a third party. During the year ended December 31, 2011, the Company acquired the remaining 10% interest in Talbot for $28 million, increasing its ownership interest to 100%. Effective October 21, 2011, ownership of Talbot was transferred to the Fund.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31, *(millions of Canadian dollars)*	**2011**	2010	2009
Balance at beginning of year	**362**	236	183
Earnings	**(7)**	12	16
Other comprehensive loss			
Change in unrealized loss on cash flow hedges, net of tax	**(3)**	(13)	(2)
Comprehensive income/(loss)	**(10)**	(1)	14
Distributions to unitholders	**(33)**	(23)	(23)
Contributions from unitholders	**168**	-	-

Redemption value adjustment	**153**	150	62
Balance at end of year	**640**	362	236

Redeemable noncontrolling interests in the Fund at December 31, 2011 represent 64.6% (2010 - 58.2%; 2009 - 58.2%) of interests that are held by third parties. During the year ended December 31, 2011, the Fund acquired the Ontario Wind, Sarnia Solar and Talbot Wind energy projects from a wholly-owned subsidiary of Enbridge for proceeds of $1.2 billion. Ordinary trust units were issued by the Fund to partially finance the acquisition, resulting in an increase in interests held by third parties. Contributions from redeemable noncontrolling interests for the year ended December 31, 2011 consist of $168 million attributable to the Fund s common trust unit issuance.

19. 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 preferred shares.

COMMON SHARES

	2011		2010		2009	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars, number of common shares in millions)						
Balance at beginning of year	**770**	**3,683**	756	3,379	746	3,194
Common shares issued	**-**	**-**	-	-	-	4
Shares issued on exercise of stock options	**4**	**57**	6	80	2	38
Dividend Reinvestment and Share Purchase Plan (DRIP)	**7**	**229**	8	224	8	143
Balance at end of year	**781**	**3,969**	770	3,683	756	3,379

PREFERENCE SHARES

	2011		2010		2009	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	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 issued[1]	**20**	**490**	-	-	-	-
Preference shares, Series D issued[2]	**18**	**441**	-	-	-	-
Balance at end of year		**1,056**		125		125

1 Gross proceeds - $500 million; net issuance costs - $10 million.

2 Gross proceeds - $450 million; net issuance costs - $9 million.

Characteristics of the preference shares are as follows:

(Canadian dollars unless otherwise stated)	Initial Yield	Dividend1	Per Share Cash Dividend Declared	Per Share Base Redemption Value2	Redemption and Conversion Option Date 2,3	Right to Convert3,4
Preference shares, Series A	5.5%	1.3750	1.3750	25	-	-
Preference shares, Series B	4.0%	1.0000	0.4192	25	June 1, 2017	Series C
Preference shares, Series D	4.0%	1.0000	0.2705	25	March1, 2018	Series E

1 Fixed, cumulative, quarterly preferential dividend per share per year.

2 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 + 2.40% (Series C) or 2.37% (Series E)).

Subsequent to year end, on January 18, 2012, the Company issued 20 million Series F Preference Shares for gross proceeds of $500 million. The 4.0% Cumulative Redeemable Preference Shares, Series F are entitled to the same dividends, redemption and conversion terms as the Series B and Series D Preference Shares. Redemption of Series F Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series G can occur on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Series G Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to $25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day Government of Canada treasury bill rate plus 2.51%.

Subsequent to year end, on March 29, 2012, the Company issued 14 million Series H Preference Shares for gross proceeds of $350 million. The 4.0% Cumulative Redeemable Preference Shares, Series H are entitled to same dividends, redemption and conversion terms as the Series B, Series D and Series F Preference Shares. Redemption of Series H Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series I can occur on September 1, 2018 and on September 1 of every fifth year thereafter. The holders of Series H Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to $25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day Government of Canada Treasury bill rate plus 2.12%.

Subsequent to year end, on April 19, 2012, the Company issued 8 million Series J Preference Shares for gross proceeds of US $200 million. The 4.0% Cumulative Redeemable Preference Shares, Series J are entitled to the same dividends and similar redemption and conversion terms as the Series B, Series D, Series F and Series H Preference Shares, except that any cash payments are to be made in U.S. dollars. Redemption of Series J Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series K can occur on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Series K Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to US$25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day US Government Treasury bill rate plus 3.05%.

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 25 million (2010 - 22 million; 2009 - 22 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,	**2011**	2010	2009
(number of common shares in millions)			
Weighted average shares outstanding	**751**	741	728
Effect of dilutive options	**10**	7	5
Diluted weighted average shares outstanding	**761**	748	733

For the year ended December 31, 2011, 48,000 anti-dilutive stock options (2010 - 92,000; 2009 - 1,113,000) with a weighted average exercise price of $32.02 (2010 - $27.84; 2009 - $20.49) 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.

20. 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 43 million have been issued to date. In 2007, a new reserve of 33 million shares was approved and established and in 2011 an increase of 19 million to the reserved common shares was approved, resulting in a total of 52 million common shares being available for the 2007 ISO and PBSO plans, of which 1 million have been issued 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 ISOs to purchase common shares at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date. Compensation expense recorded for the year ended December 31, 2011 for ISOs was $16 million (2010 - $11 million; 2009 - $17 million).

Outstanding Incentive Stock Options

	2011		2010		2009	
December 31,	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
Options at beginning of year	**25,460**	**18.34**	24,932	17.01	21,300	15.53
Options granted	**6,041**	**28.78**	4,000	22.70	6,056	19.81
Options exercised	**(3,926)**	**14.23**	(3,436)	14.52	(2,374)	11.01
Options cancelled or expired	**(110)**	**25.87**	(36)	12.45	(50)	20.33
Options at end of year	**27,465**	**21.19**	25,460	18.34	24,932	17.01
Options vested	**14,214**	**17.93**	13,764	16.01	13,100	14.48

The total intrinsic value of ISOs exercised during the year ended December 31, 2011 was $68 million (2010 - $38 million; 2009 - $22 million) and cash received on exercise was $56 million (2010 - $50 million; 2009 - $26 million). Intrinsic value represents the difference between the Company s share price and the exercise price, multiplied by the number of options. The total intrinsic value of ISOs outstanding and vested at December 31, 2011 was $285 million (2010 - $182 million) and $194 million (2010 - $131 million), respectively.

Incentive Stock Option Characteristics

	Options Outstanding			Options Vested		
December 31, 2011 Exercise Price Range	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
10.00-12.49	**1,195**	**1.0**	**10.45**	**1,195**	**1.0**	**10.45**
12.50-14.99	**1,440**	**2.1**	**12.86**	**1,440**	**2.1**	**12.86**

15.00-17.49	**2,578**	**4.7**	**15.99**	**1,963**	**4.0**	**15.94**
17.50-19.99	**7,877**	**6.0**	**19.30**	**5,486**	**5.5**	**19.08**
20.00-22.49	**5,202**	**6.4**	**20.55**	**3,390**	**6.2**	**20.37**
22.50-24.99	**3,102**	**8.1**	**23.30**	**717**	**8.1**	**23.30**
27.50-29.99	**6,023**	**9.1**	**28.90**	**23**	**8.9**	**27.84**
30.00-32.49	**48**	**9.7**	**32.02**	**-**	**-**	**-**
	27,465	**6.5**	**21.08**	**14,214**	**4.9**	**17.83**

The total fair value of options vested under the ISO Plan during the year ended December 31, 2011 was $17 million (2010 - $14 million; 2009 - $13 million).

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

Year ended December 31,	**2011**	2010	2009
Fair value per option *(Canadian dollars)*1	**4.19**	3.44	3.56
Valuation assumptions			
Expected option term *(years)*2	**6**	6	6
Expected volatility3	**18.63%**	19.72%	28.08%
Expected dividend yield4	**3.40%**	3.64%	3.87%
Risk-free interest rate5	**2.85%**	2.70%	2.24%

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 $4.01 (2010 - $3.28; 2009 - $3.37) for Canadian employees and US $5.11 (2010 - US$4.00; 2009 - US$3.43) 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. Beginning in 2010, implied volatility observable in call option values near the grant date is also considered in determining the expected volatility.

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.

At December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the ISO Plan was $24 million. The cost is expected to be fully recognized by December 31, 2014.

PERFORMANCE BASED STOCK OPTIONS

PBSOs are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PBSOs were granted on September 16, 2002 under the 2002 plan and on August 15, 2007 and February 19, 2008 under the 2007 plan. All performance and time vesting conditions on the 2002 grant were met prior to the term of the options expiring on September 16, 2010. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements will be fulfilled evenly over a five-year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Compensation expense recorded for the year ended December 31, 2011 for PBSOs was $2 million (2010 - $2 million; 2009 - $2 million).

Outstanding Performance Based Stock Options

	2011	2010		2009	
December 31,	Number	Number	Weighted Average Exercise	Number	Weighted Average Exercise

(options in thousands; exercise price in Canadian dollars)		Weighted Average Exercise Price		Price		Price
Options at beginning of year	**4,294**	**18.51**	6,790	16.85	7,476	16.36
Options exercised	**(167)**	**18.29**	(2,078)	13.12	(686)	11.58
Options cancelled	**-**	**-**	(418)	18.29	-	-
Options at end of year	**4,127**	**18.52**	4,294	18.51	6,790	16.85
Options vested	**3,191**	**18.47**	2,524	18.44	1,600	11.58

The total intrinsic value of PBSOs exercised during the year ended December 31, 2011 was $2 million (2010 - $26 million; 2009 - $6 million) and cash received on exercise was $3 million (2010 - $27 million; 2009 - $8 million). The total intrinsic value of PBSOs outstanding and vested at December 31, 2011 was $54 million (2010 - $30 million) and $42 million (2010 - $18 million), respectively.

Performance Based Stock Option Characteristics

	Options Outstanding			Options Vested		
December 31, 2011 Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price	Number	Weighted Average Remaining Life *(years)*	Weighted Average Exercise Price
(options in thousands; exercise price in Canadian dollars)						
18.29	**3,627**	**3.6**	**18.29**	**2,891**	**3.6**	**18.29**
20.21	**500**	**3.6**	**20.21**	**300**	**3.6**	**20.21**
	4,127	**3.6**	**18.52**	**3,191**	**3.6**	**18.47**

The total fair value of options vested under the PBSO Plan during the year ended December 31, 2011 was $2 million (2010 - $2 million; 2009 - $2 million).

At December 31, 2011, unrecognized compensation cost related to non-vested share-based compensation arrangements granted under the PBSO Plan was $1 million. The cost is expected to be fully recognized by December 31, 2012.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for senior officers 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 2009, 2010 and 2011 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 non-operating or non-recurring items, relative to targets established at the time of grant.

Compensation expense recorded for the year ended December 31, 2011 for PSUs was $42 million (2010 - $27 million; 2009 - $20 million). To calculate the 2011 expense, multipliers of two, based upon multiplier estimates at December 31, 2011, were used for each of the 2009, 2010 and 2011 PSU grants.

Outstanding Performance Stock Units

December 31,	**2011**	2010	2009
Units at beginning of year	**955,894**	660,832	590,856
Units granted	**317,000**	572,400	339,200
Units matured	**(375,190)**	(319,634)	(303,764)
Dividend reinvestment	**39,453**	42,296	34,540
Units at end of year	**937,157**	955,894	660,832

Of the PSUs outstanding at December 31, 2011, 610,459 units have a performance period ending December 31, 2012 and 326,698 have a performance period ending December 31, 2013. The total intrinsic value of PSUs outstanding at December 31, 2011 is $71 million (2010 - $54 million; 2009 - $31 million). The total amount paid during the year ended December 31, 2011 for PSUs was $17 million (2010 - $14 million; 2009 - $9 million).

As of December 31, 2011, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $34 million and is expected to be fully recognized by December 31, 2013.

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. Compensation expense recorded for the year ended December 31, 2011 for RSUs was $31 million (2010 - $29 million; 2009 - $23 million).

December 31,	**2011**	2010	2009
Units at beginning of year	**2,095,970**	1,975,754	1,400,068
Units granted	**938,100**	937,200	1,087,000
Units cancelled	**(92,276)**	(60,908)	(36,858)
Units matured	**(1,132,674)**	(855,504)	(565,312)
Dividend reinvestment	**92,865**	99,428	90,856
Units at end of year	**1,901,985**	2,095,970	1,975,754

The total intrinsic value of RSUs outstanding at December 31, 2011 was $72 million (2010 - $59 million; 2009 - $47 million). The total liability paid during the year ended December 31, 2011 for RSUs was $39 million (2010 - $24 million; 2009 - $12 million).

As of December 31, 2011, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $34 million and is expected to be fully recognized by December 31, 2013.

The income tax benefit related to stock-based compensation expense was $4 million, $6 million and $2 million for 2011, 2010 and 2009, respectively.

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

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension Actuarial Gain/Loss Adjustment	Total
Balance at January 1, 2009	40	278	(280)	(9)	(117)	(88)
Changes during the year	10	181	(753)	(6)	23	(545)
Tax impact	19	(30)	-	-	(10)	(21)
	29	151	(753)	(6)	13	(566)
Balance at December 31, 2009	69	429	(1,033)	(15)	(104)	(654)
Changes during the year	(136)	61	(255)	3	(52)	(379)
Tax impact	1	(10)	-	1	14	6
	(135)	51	(255)	4	(38)	(373)
Balance at December 31, 2010	(66)	480	(1,288)	(11)	(142)	(1,027)
Changes during the year	**(563)**	**(21)**	**85**	**(20)**	**(200)**	**(719)**

Tax impact	**153**	**2**	**-**	**3**	**56**	**214**
	(410)	**(19)**	**85**	**(17)**	**(144)**	**(505)**
Balance at December 31, 2011	**(476)**	**461**	**(1,203)**	**(28)**	**(286)**	**(1,532)**

22. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET PRICE RISK

The Company s earnings, cash flows and OCI are subject to movements in foreign exchange rates, interest rates, 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. The Company has implemented a policy where it economically hedges a minimum level of foreign currency denominated earnings exposures identified over the next five year period. 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 2016 with an average swap rate of 2.38%.

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 2015. A total of $7,050 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.86%.

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 band 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 NGLs. 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.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGLs) that impact earnings from its ownership interest in the Aux Sable natural gas processing plant and the gathering and processing business held by EEP.

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, RSUs (*Note 20*). 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 balance sheet location and carrying value of the Company s derivative instruments. The Company did not have any outstanding fair value hedges at December 31, 2011 or 2010.

December 31, 2011	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments1
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
Foreign exchange contracts	**4**	**15**	**315**	**334**	**-**	**334**
Interest rate contracts	**-**	**-**	**12**	**12**	**(4)**	**8**
Commodity contracts	**7**	**-**	**146**	**153**	**(19)**	**134**
Other contracts	**3**	**-**	**7**	**10**	**-**	**10**
	14	**15**	**480**	**509**	**(23)**	**486**
Deferred amounts and other *(Note 12)*						
Foreign exchange contracts	**15**	**79**	**203**	**297**	**-**	**297**
Interest rate contracts	**1**	**-**	**24**	**25**	**(3)**	**22**
Commodity contracts	**12**	**-**	**241**	**253**	**(15)**	**238**
Other contracts	**3**	**-**	**2**	**5**	**-**	**5**
	31	**79**	**470**	**580**	**(18)**	**562**
Accounts payable and other *(Note 15)*						
Foreign exchange contracts	**(4)**	**-**	**(275)**	**(279)**	**-**	**(279)**
Interest rate contracts	**(477)**	**-**	**(8)**	**(485)**	**4**	**(481)**
Commodity contracts	**(32)**	**-**	**(107)**	**(139)**	**19**	**(120)**
	(513)	**-**	**(390)**	**(903)**	**23**	**(880)**
Other long-term liabilities *(Note 17)*						
Foreign exchange contracts	**(35)**	**(5)**	**(51)**	**(91)**	**-**	**(91)**
Interest rate contracts	**(415)**	**-**	**(20)**	**(435)**	**3**	**(432)**
Commodity contracts	**(29)**	**-**	**(20)**	**(49)**	**15**	**(34)**
	(479)	**(5)**	**(91)**	**(575)**	**18**	**(557)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(20)**	**89**	**192**	**261**	**-**	**261**
Interest rate contracts	**(891)**	**-**	**8**	**(883)**	**-**	**(883)**
Commodity contracts	**(42)**	**-**	**260**	**218**	**-**	**218**
Other contracts	**6**	**-**	**9**	**15**	**-**	**15**
	(947)	**89**	**469**	**(389)**	**-**	**(389)**

December 31, 2010 *(millions of Canadian dollars)*	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments1
Accounts receivable and other *(Note 7)*						
Foreign exchange contracts	4	15	111	130	-	130
Interest rate contracts	29	-	5	34	(5)	29
Commodity contracts	11	-	56	67	(20)	47
Other contracts	-	-	1	1	-	1
	44	15	173	232	(25)	207
Deferred amounts and other *(Note 12)*						
Foreign exchange contracts	18	100	275	393	-	393
Interest rate contracts	69	-	8	77	(6)	71
Commodity contracts	14	-	10	24	(21)	3
	101	100	293	494	(27)	467
Accounts payable and other *(Note 15)*						
Foreign exchange contracts	(4)	-	(11)	(15)	-	(15)
Interest rate contracts	(93)	-	(5)	(98)	5	(93)
Commodity contracts	(43)	-	(86)	(129)	20	(109)
	(140)	-	(102)	(242)	25	(217)
Other long-term liabilities *(Note 17)*						
Foreign exchange contracts	(47)	-	(3)	(50)	-	(50)
Interest rate contracts	(124)	-	(6)	(130)	6	(124)
Commodity contracts	(38)	-	(10)	(48)	21	(27)
	(209)	-	(19)	(228)	27	(201)
Total net derivative asset/(liability)						
Foreign exchange contracts	(29)	115	372	458	-	458
Interest rate contracts	(119)	-	2	(117)	-	(117)
Commodity contracts	(56)	-	(30)	(86)	-	(86)
Other contracts	-	-	1	1	-	1
	(204)	115	345	256	-	256

1 *As presented in the Consolidated Statements of Financial Position.*

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

December 31, 2011	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - U.S. dollar forwards - purchase *(millions of United States dollars)*	**58**	**287**	**468**	**25**	**25**	**418**
Foreign exchange contracts - U.S. dollar forwards - sell *(millions of United States dollars)*	**2,017**	**1,865**	**2,182**	**2,583**	**2,039**	**180**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**3,227**	**3,237**	**2,787**	**2,641**	**2,428**	**215**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**2,650**	**2,000**	**1,650**	**750**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**36**	**26**	**-**	**-**	**-**	**-**

Commodity contracts - natural gas *(billions of cubic feet)*	**20**	**59**	**1**	**1**	**1**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**11**	**26**	**17**	**8**	**7**	**10**
Commodity contracts - NGL *(millions of barrels)*	**4**	**1**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatts per hour)*	**40**	**28**	**40**	**48**	**63**	**58**

December 31, 2010	2011	2012	2013	2014	2015	Thereafter
Foreign exchange contracts - U.S. dollar forwards - purchase *(millions of United States dollars)*	165	54	54	454	25	432
Foreign exchange contracts - U.S. dollar forwards - sell *(millions of United States dollars)*	775	541	538	842	698	123
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	3,373	3,052	2,732	1,737	127	42
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	1,098	997	698	398	-	-
Equity contracts *(millions of Canadian dollars)*	16	13	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	70	13	5	-	-	-
Commodity contracts - crude oil *(millions of barrels)*	9	1	1	1	-	-
Commodity contracts - NGL *(millions of barrels)*	4	2	1	-	-	-
Commodity contracts - power *(megawatts per hour)*	9	2	2	2	2	2

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.

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(22)**	(25)	(116)
Interest rate contracts	**(724)**	(217)	89
Commodity contracts	**72**	128	(187)
Other contracts	**6**	(1)	3
Net investment hedges			
Foreign exchange contracts	**(26)**	19	24
	(694)	(96)	(187)
Amount of gain/(loss) reclassified from AOCI to earnings *(effective portion)*			
Foreign exchange contracts[1]	**1**	(7)	(4)
Interest rate contracts[2]	**(10)**	61	(33)
Commodity contracts[3]	**(55)**	(116)	(37)
Other contracts[4]	**(2)**	1	3
	(66)	(61)	(71)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts [2]	**11**	-	-
Commodity contracts [3]	**5**	(3)	1
	16	(3)	1

1 *(Gain)/loss reported within Other income in the Consolidated Statement of Earnings.*

2 *(Gain)/loss reported within Interest expense in the Consolidated Statement of Earnings.*

3 *(Gain)/loss reported within Commodity costs in the Consolidated Statement of Earnings.*

4 *(Gain)/loss reported within Operating and administrative expense in the Consolidated Statement of Earnings.*

The Company estimates that $7 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 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, 2011.

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,	**2011**	2010	2009
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**(179)**	33	232
Interest rate contracts [2]	**9**	(3)	3
Commodity contracts [3]	**280**	(12)	(104)
Other contracts[4]	**4**	-	-
Total unrealized derivative fair value gain	**114**	18	131

1 Gain/loss) reported within Transportation and other services revenue and Other income in the Consolidated Statement of Earnings.

2 Gain/(loss) reported within Interest expense in the Consolidated Statement of Earnings.

3 Gain/(loss) reported within Transportation and other services revenue, Commodity costs, and Operating and administrative expenses in the Consolidated Statement of Earnings.

4 Gain/(loss) reported within Operating and administrative expense in the Consolidated Statement of Earnings.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees *(Notes 28 and 29)* 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 *(Note 16)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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 generally has a policy of entering into individual International Securities Dealers Association (ISDA) agreements, or other similar derivative agreements, with the majority of our 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 our credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011 and 2010, the Company had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

December 31,	**2011**	2010
(millions of Canadian dollars)		
Canadian financial institutions	**431**	458
U.S. financial institutions	**287**	109
Other	**369**	209
	1,087	776

As of December 31, 2011, the Company has provided letters of credit totaling $176 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company holds no cash collateral on asset exposures at December 31, 2011 or 2010.

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

The 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. All equity investments of this nature held by the Company at December 31, 2011 and December 31, 2010 are recognized at cost with a carrying value of $57 million at December 31, 2011 (2010 - $61 million).

At December 31, 2011, the Company s long-term debt had a carrying value of $19,605 million (2010 - $18,588 million) and a fair value of $22,620 million (2010 - $20,066 million). The fair value of the Company s long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure.

Fair Value of Derivatives

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

Level 1

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

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. These instruments are used primarily in the Gas Pipelines, Processing and Energy Services, Sponsored Investments and Corporate segments.

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 in the Gas Pipelines, Processing and Energy Services and Sponsored Investments segments.

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 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) 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.

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

December 31, 2011	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	**-**	**334**	**-**	**334**	**-**	**334**
Interest rate contracts	**-**	**12**	**-**	**12**	**(4)**	**8**
Commodity contracts	**1**	**66**	**86**	**153**	**(19)**	**134**
Other contracts	**-**	**10**	**-**	**10**	**-**	**10**
	1	**422**	**86**	**509**	**(23)**	**486**
Long-term derivative assets						
Foreign exchange contracts	**-**	**297**	**-**	**297**	**-**	**297**
Interest rate contracts	**-**	**25**	**-**	**25**	**(3)**	**22**
Commodity contracts	**-**	**208**	**45**	**253**	**(15)**	**238**
Other contracts	**-**	**5**	**-**	**5**	**-**	**5**
	-	**535**	**45**	**580**	**(18)**	**562**
Financial liabilities						
Current derivative liabilities	**-**	**(279)**	**-**	**(279)**	**-**	**(279)**
Foreign exchange contracts	**-**	**(485)**	**-**	**(485)**	**4**	**(481)**
Interest rate contracts	**-**	**(59)**	**(80)**	**(139)**	**19**	**(120)**
Commodity contracts	**-**	**-**	**-**	**-**	**-**	**-**
	-	**(823)**	**(80)**	**(903)**	**23**	**(880)**
Long-term derivative liabilities						
Foreign exchange contracts	**-**	**(91)**	**-**	**(91)**	**-**	**(91)**
Interest rate contracts	**-**	**(435)**	**-**	**(435)**	**3**	**(432)**
Commodity contracts	**-**	**(30)**	**(19)**	**(49)**	**15**	**(34)**
	-	**(556)**	**(19)**	**(575)**	**18**	**(557)**
Total net financial asset/(liability)						
Foreign exchange contracts	**-**	**261**	**-**	**261**	**-**	**261**
Interest rate contracts	**-**	**(883)**	**-**	**(883)**	**-**	**(883)**
Commodity contracts	**1**	**185**	**32**	**218**	**-**	**218**
Other contracts	**-**	**15**	**-**	**15**	**-**	**15**
	1	**(422)**	**32**	**(389)**	**-**	**(389)**

December 31, 2010	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	-	130	-	130	-	130
Interest rate contracts	-	34	-	34	(5)	29
Commodity contracts	-	8	59	67	(20)	47
Other contracts	-	-	1	1	-	1
	-	172	60	232	(25)	207
Long-term derivative assets						
Foreign exchange contracts	-	393	-	393	-	393
Interest rate contracts	-	77	-	77	(6)	71
Commodity contracts	-	2	22	24	(21)	3
	-	472	22	494	(27)	467
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	-	(15)	-	(15)	-	(15)
Interest rate contracts	-	(98)	-	(98)	5	(93)
Commodity contracts	(9)	(35)	(85)	(129)	20	(109)
	(9)	(148)	(85)	(242)	25	(217)
Long-term derivative liabilities						
Foreign exchange contracts	-	(50)	-	(50)	-	(50)
Interest rate contracts	-	(130)	-	(130)	6	(124)
Commodity contracts	-	(27)	(21)	(48)	21	(27)
	-	(207)	(21)	(228)	27	(201)
Total net financial asset/(liability)						
Foreign exchange contracts	-	458	-	458	-	458
Interest rate contracts	-	(117)	-	(117)	-	(117)
Commodity contracts	(9)	(52)	(25)	(86)	-	(86)
Other contracts	-	-	1	1	-	1
	(9)	289	(24)	256	-	256

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,	**2011**	2010
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of year	**(24)**	(30)
Total unrealized gains/(losses)		
Included in earnings[1]	**31**	20
Included in OCI	**(41)**	(10)
Purchases	**8**	-
Settlements	**58**	(4)
Level 3 net derivative asset/(liability) at end of year	**32**	(24)

1 Gain reported within Transportation and other services revenue, 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 of December 31, 2011 or 2010.

23. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings before income taxes, discontinued operations and extraordinary item	**2,030**	1,008	2,134
Combined statutory income tax rate	**27.2%**	28.8%	30.4%
Income taxes at statutory rate	**552**	290	649
Increase/(decrease) resulting from:			
Deferred income taxes related to regulated operations	**(35)**	(62)	(68)
Higher/(lower) foreign tax rates	**65**	(38)	(42)
Tax rates and legislated tax changes	**1**	(15)	(52)
Non-taxable items, net	**(16)**	(8)	2
Intercompany sale of investments[1]	**98**	-	-
Sale of investments	**-**	-	(99)
Non-controlling interests	**(130)**	55	(69)
Other	**(9)**	5	(9)
Income taxes before discontinued operations and extraordinary item	**526**	227	312
Effective income tax rate	**25.9%**	22.5%	14.6%

1 In October 2011, EPI sold three renewable energy assets to the Fund. As the transaction occurred between entities under common control of the Company, the intercompany gain realized as a result of this transfer has been eliminated, although cash income taxes of $98 million remain as a charge to earnings. The Company retains the benefit of cash taxes paid in the form of increased tax basis of its investment in the underlying partnerships; however, accounting recognition of such benefit is not permitted until such time as the partnerships are sold outside of the consolidated group.

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Earnings before income taxes attributable to Enbridge Inc.			
Canada	**439**	742	930
United States	**787**	305	320
Other	**133**	131	580
	1,359	1,178	1,830
Current income taxes			
Canada	**194**	(24)	40
United States	**(30)**	43	39
Other	**(6)**	5	4
	158	24	83
Deferred income taxes			
Canada	**30**	136	130
United States	**338**	67	99
	368	203	229
Total income taxes before discontinued operations and extraordinary item	**526**	227	312

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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,	**2011**	2010
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(1,499)**	(1,213)
Investments	**(973)**	(822)
Regulatory liabilities	**(197)**	(262)
Financial instruments	**(165)**	(127)
Other	**(117)**	(97)
Total deferred income tax liabilities	**(2,951)**	(2,521)
Deferred income tax assets		
Financial instruments	**202**	48
Pension and other benefit plans	**145**	93
Loss carryforwards	**174**	99
Other	**29**	27
Total deferred income tax assets	**550**	267
Less valuation allowance	**(45)**	(18)
Total deferred income tax assets, net	**505**	249
Net deferred income tax liabilities	**(2,446)**	(2,272)
Presented as follows:		
Assets		
Accounts receivable and other *(Note 7)*	**108**	2
Deferred income taxes	**29**	20
Total deferred income tax assets	**137**	22
Liabilities		
Accounts payable and other *(Note 15)*	**(11)**	(47)
Deferred income taxes	**(2,572)**	(2,247)
Total deferred income tax liabilities	**(2,583)**	(2,294)
Net deferred income tax liabilities	**(2,446)**	(2,272)

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.

At December 31, 2011, the Company recognized the benefit of unused tax loss carryforwards of $214 million (2010 - $95 million, 2009 - $142 million) in Canada of which $214 million start to expire in 2020 and beyond.

At December 31, 2011, the Company recognized the benefit of unused tax loss carryforwards of $187 million (2010 - $153 million, 2009 - $282 million) in the United States of which $187 million start to expire in 2020 and beyond.

The Company has not provided for deferred income taxes on $524 million (2010 - $491 million) of foreign subsidiaries undistributed earnings as at December 31, 2011 as such earnings are intended to be indefinitely reinvested in the operations and potential acquisitions. Upon distribution of these earnings in the form of dividends or otherwise, the Company would be subject to income taxes. It is not practicable to determine the income tax liability that might be incurred if these earnings were to be distributed.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of Income taxes. Income taxes for the year ended December 31, 2011 includes $1 million expense (2010 - $2 million recovery; 2009 - $1 million expense) of interest and penalties. As at December 31, 2011, interest and penalties of $9 million (2010 - $8 million) have been accrued.

The Company and its subsidiaries are subject to taxation in Canada and the United States. The Company is under examination by certain tax authorities for the 2007 to 2010 tax years. The material jurisdictions in which the Company is subject to potential examinations include the United States (Federal and Texas) and Canada (Federal, Alberta and Ontario).

UNRECOGNIZED TAX BENEFITS

Year ended December, 31	**2011**	2010
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**17**	22
Gross increases for tax positions of current year	**3**	2
Gross increases for tax positions of prior years	**-**	-
Gross decreases for tax positions of prior years	**(1)**	(2)
Reduction for lapse of statute of limitations	**(1)**	(2)
Changes in translation of foreign currency	**-**	-
Decreases relating to settlements with taxing authority	**-**	(3)
Unrecognized tax benefits at end of year	**18**	17

The unrecognized tax benefits at December 31, 2011, if recognized, would affect the Company s effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.

24. 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 Liquids Pipelines and Gas Distribution pension plans (collectively, 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, 2011 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. 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, 2010	December 31, 2011
Gas Distribution	December 31, 2009	December 31, 2012
United States Plan	December 31, 2010	December 31, 2011

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.

DEFINED BENEFIT PLANS

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,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**1,323**	1,119	**195**	170
Service cost	**61**	48	**6**	5
Interest cost	**73**	72	**11**	11
Amendments	**-**	-	**-**	6
Employees contributions	**-**	-	**1**	1
Actuarial loss[1]	**270**	145	**28**	12
Benefits paid	**(54)**	(52)	**(7)**	(7)
Other	**8**	-	**7**	-
Effect of foreign exchange rate changes	**5**	(9)	**2**	(3)
Benefit obligation at end of year	**1,686**	1,323	**243**	195
Change in plan assets				
Fair value of plan assets at beginning of year	**1,314**	1,158	**41**	38
Actual return on plan assets	**16**	127	**1**	2
Employer s contributions	**72**	89	**13**	9
Employees contributions	**-**	-	**1**	1
Benefits paid	**(54)**	(52)	**(7)**	(7)
Effect of foreign exchange rate changes	**3**	(6)	**1**	(2)
Other	**4**	(2)	**4**	-
Fair value of plan assets at end of year	**1,355**	1,314	**54**	41
Underfunded status at end of year	**(331)**	(9)	**(189)**	(154)
Presented as follows:				
Deferred amounts and other assets *(Note 12)*	**-**	58	**-**	-
Accounts payable and other	**-**	-	**(5)**	(5)
Other long-term liabilities *(Note 17)*	**(331)**	(67)	**(184)**	(149)
	(331)	(9)	**(189)**	(154)

1 *Includes revaluing plan assets and liabilities for December 31, 2010.*

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,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**4.46%**	5.64%	6.46%	**4.44%**	5.55%	6.28%
Average rate of salary increases	**3.50%**	3.50%	3.73%			

Net Benefit Costs Recognized

	Pension			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
(millions of Canadian dollars)						
Benefits earned during the year	**61**	48	53	**6**	5	4
Interest cost on projected benefit obligations	**73**	72	71	**11**	11	11
Actual return on plan assets	**(16)**	(127)	(51)	**(1)**	(2)	(6)
Difference between actual and expected return on plan assets	**(76)**	47	(27)	**(2)**	-	3
Amortization of prior service costs	**2**	2	2	**1**	-	-
Amortization of actuarial loss	**25**	19	21	**1**	1	1
Net defined benefit costs on an accrual basis	**69**	61	69	**16**	15	13
Defined contribution benefit costs	**4**	5	4	**-**	-	-
Net benefit cost recognized in the Consolidated Statements of Earnings	**73**	66	73	**16**	15	13
Net amount recognized in OCI						
Net actuarial loss/(gain)[1]	**172**	35	(14)	**29**	11	(9)
Net prior service cost/(credit)[2]	**-**	-	-	**(1)**	6	-
Total amount recognized in OCI	**172**	35	(14)	**28**	17	(9)
Total net benefit cost and amount recognized in OCI	**245**	101	59	**44**	32	4

1 Unamortized actuarial losses included in AOCI were $346 million (2010 - $174 million) relating to the pension plans and $51 million (2010 - $22 million) relating to OPEB at December 31, 2011.

2 Unamortized prior service costs included in AOCI were $5 million (2010 - $6 million) relating to OPEB at December 31, 2011.

The Company estimates that approximately $25 million related to pension plans and OPEB at December 31, 2011 will be reclassified into earnings in the next twelve months, as follows.

	Pension Benefits	OPEB	Total
(millions of Canadian dollars)			
Prior service costs	**-**	**1**	**1**
Actuarial Loss	**22**	**2**	**24**
	22	**3**	**25**

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. Differences arise since accounting is based on an accrual basis whereas ratemaking is based on a cash basis or funding approach. Regulatory assets or liabilities recognized in the Consolidated Statements of Financial Position are disclosed in Note 5.

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

	Pension			OPEB		
Year ended December 31,	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**5.64%**	6.47%	6.59%	**5.55%**	6.31%	6.42%
Average rate of return on pension plan assets	**7.30%**	7.30%	7.30%	**6.00%**	6.00%	6.09%
Average rate of salary increases	**3.50%**	3.73%	5.00%			

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	8.4%	4.5%	2029
Other Medical and Dental	4.5%	4.5%	2029
United States Plan	7.8%	4.5%	2030

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $36 million in the benefit obligation and an increase of $3 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $29 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.

Target Mix for Plan Assets

	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%

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Canadian Plans	**7.00%**	7.25%		
United States Plan	**7.50%**	7.75%	**6.00%**	6.00%

55

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, 2011, the pension assets were invested 56.7% (2010 - 60.3%) in equity securities, 36.6% (2010 - 34.1%) in fixed income securities and 6.7% (2010 - 5.6%) in other. The OPEB assets were invested 55.3% (2010 - 51.2%) in equity securities, 40.3% (2010 - 48.8%) in fixed income securities and 4.4% (2010 - nil) in other.

The following table summarizes the Company s pension financial instruments at fair value. Non-financial instruments with a carrying value of $77 million (2010 - $64 million) have been excluded from the table below.

	2011				2010			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension								
Cash and cash equivalents	**14**	**-**	**-**	**14**	10	-	-	10
Fixed income securities								
Canadian government bonds	**-**	**115**	**-**	**115**	-	97	-	97
Corporate bonds and debentures	**-**	**4**	**-**	**4**	4	-	-	4
Canadian corporate bond index fund	**158**	**-**	**-**	**158**	151	-	-	151
Canadian government bond index fund	**157**	**-**	**-**	**157**	149	-	-	149
United States debt index fund	**62**	**-**	**-**	**62**	47	-	-	47
Equity								
Canadian equity securities	**148**	**-**	**-**	**148**	163	-	-	163
Canadian equity funds	**21**	**74**	**-**	**95**	24	80	-	104
United States equity funds	**170**	**89**	**-**	**259**	145	76	-	221
Global equity funds	**191**	**7**	**-**	**198**	220	19	-	239
Private equity investment[4]	**-**	**-**	**68**	**68**	-	-	65	65
OPEB								
Cash and cash equivalents	**3**	**-**	**-**	**3**	-	-	-	-
Fixed income securities								
United States government and government agency bonds	**22**	**-**	**-**	**22**	20	-	-	20
Equity								
United States equity funds	**15**	**14**	**-**	**29**	9	-	-	9
Global equity funds	**-**	**-**	**-**	**-**	-	12	-	12

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.*

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

	2011	2010
(millions of Canadian dollars)		
Balance at beginning of year	**65**	37
Contributions	**5**	27
Unrealized gains	**8**	7
Distributions	**(10)**	(6)
Balance at end of year	**68**	65

Plan Contributions by the Company

	Pension		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Total contributions	**72**	89	**13**	9
Contributions expected to be paid in 2012	**94**		**11**	

Benefits Expected to be Paid by the Company

Year ended December 31,	2012	2013	2014	2015	2016	2017-2021
(millions of Canadian dollars)						
Expected future benefit payments	66	68	72	76	80	466

25. OTHER INCOME

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Net foreign currency gains	**48**	132	444
Allowance for equity funds used during construction	**3**	96	148
Interest income on affiliate loans	**17**	20	34
Interest income	**3**	17	16
Noverco preferred shares dividend income	**30**	15	15
Gain on acquisition *(Note 6)*	**-**	22	-
Hurricane insurance recoveries	**-**	5	13
Ocensa investment income	**-**	-	6
Other	**16**	11	5
	117	318	681

26. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Accounts receivable and other	**119**	(779)	230
Accounts receivable from affiliates	**(17)**	8	(24)
Inventory	**93**	(124)	62
Deferred amounts and other assets	**(311)**	(7)	(111)
Accounts payable and other	**420**	539	75
Accounts payable from affiliates	**41**	(22)	24
Interest payable	**7**	31	23
Other long-term liabilities	**51**	(70)	37
	403	(424)	316

27. 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 Pipeline, 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, 2011 (2010 - $7 million; 2009 - $6 million).

EGD, a subsidiary of the Company, has contracts for gas transportation services from Alliance Pipeline Canada, Alliance Pipeline US and Vector Pipeline. EGD is charged market prices for these services as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**25**	25	24
Alliance Pipeline US	**17**	17	18
Vector Pipeline	**25**	28	29
	67	70	71

Tidal Energy Marketing Inc. and Tidal Energy Marketing (US) L.L.C., subsidiaries of the Company, have transportation commitments, measured at market value, through 2015 on Alliance Pipeline Canada and Vector Pipeline. Amounts charged are as follows:

Year ended December 31,	**2011**	2010	2009
(millions of Canadian dollars)			
Alliance Pipeline Canada	**17**	13	9
Alliance Pipeline US	**11**	9	7
Vector Pipeline	**11**	10	16
	39	32	32

LONG-TERM NOTE RECEIVABLE FROM AFFILIATE

Amounts receivable from affiliates include a series of loans to Vector Pipeline totaling $190 million (2010 - $193 million), included in Deferred amounts and other assets. The loans have maturities ranging from 2012 to 2022 and all require quarterly interest payments. Annual interest rates on the loans vary from 5% to 8%.

28. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $4,630 million which are expected to be paid within the next five years.

Minimum future payments under operating leases are estimated at $231 million in aggregate. Estimated annual lease payments for the years ended December 31, 2012 through 2016 are $41 million, $36 million, $33 million, $25 million and $24 million, respectively, and $72 million thereafter.

ENBRIDGE GAS DISTRIBUTION INC.

Bloor Street Incident

EGD was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, EGD pleaded guilty before the Ontario Court of Justice to one charge under the OHSA and one charge under the TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by EGD was $875,000, which management believes concludes this matter.

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 23.0% combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments Segment.

Environmental Liabilities

As of December 31, 2011, the Company has $175 million (2010 - $226 million) included in current liabilities and $32 million (2010 - $44 million) included in Other long-term liabilities, that 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 of EEP s liquids and natural gas assets and penalties that have been or expect to be assessed.

EEP Lakehead System Line 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 pipelines in the vicinity were shut down, appropriate United States federal, state and local officials were notified, and emergency response crews were dispatched to oversee containment of the released crude oil and cleanup of the affected areas. The released crude oil affected approximately 61 kilometres (38 miles) of area along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan. The cause of the release remains the subject of an investigation by the National Transportation Safety Board and other United States federal and state regulatory agencies.

Pursuant to an administrative order issued by the Environmental Protection Agency (EPA) under the United States Clean Water Act, EEP was directed to clean up the released oil and remediate and restore the affected areas a process EEP had begun upon discovering the release.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs of approximately US$550 million ($96 million after-tax net to Enbridge), excluding lost revenue of approximately US$13 million ($2 million after-tax net to Enbridge), would be incurred in connection with this incident. These costs included emergency response, environmental remediation and cleanup activities associated with the crude oil release, as well as potential claims by third parties.

As at December 31, 2011, EEP revised its total estimate for this crude oil release to US$765 million ($129 million after-tax net to Enbridge), an increase of US$215 million ($33 million after-tax net to Enbridge) from December 31, 2010. The changes in estimate are primarily based on a review of costs and commitments incurred , and additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations and remediation activities, including the estimated costs related to the additional scope of work set forth in its response to the EPA directive it submitted to the EPA on October 20, 2011. During the fourth quarter of 2011, EEP resubmitted a revised work plan which was approved by the EPA on December 19, 2011.

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at December 31, 2011. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. 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 as well as expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

A crude oil release from Line 6A of EEP s Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. The pipeline in the vicinity was immediately shut down and emergency response crews were dispatched to oversee containment, cleanup and replacement of the pipeline segment. EEP estimated 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. Excavation and replacement of the pipeline segment were completed and the pipeline was returned to service on September 17, 2010. The cause of the crude oil release remains subject to investigation by United States federal and state environmental and pipeline safety regulators.

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 substantially completed.

As at December 31, 2010, EEP estimated that before insurance recoveries, and not including fines and penalties, costs for emergency response, environmental remediation and cleanup activities associated with the Line 6A crude oil release would be approximately US$45 million ($7 million after-tax net to Enbridge), excluding lost revenue of approximately US$3 million ($1 million after-tax net to Enbridge).

As at December 31, 2011, EEP revised its cost estimate for this crude oil release to US$48 million ($7 million after-tax net to Enbridge), before insurance recoveries and excluding fines and penalties. The US$3 million increase was based on a refinement of future costs based on additional information.

EEP included those costs it considered probable and that it could reasonably estimate for purposes of determining its expected losses associated with the Line 6A crude oil release. The estimates do not include consideration of any unasserted claims associated with the release that later may become evident, nor has EEP considered any potential recoveries from third-parties that may later be determined to have contributed to the 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 in May of each year. The program 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 increased estimate of costs associated with the crude oil releases, Enbridge and its affiliates will exceed the limits of its coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$335 million ($50 million after-tax net to Enbridge) for the year ended December 31, 2011 for insurance claims filed in connection with the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery is probable.

During the second quarter of 2011, the Company renewed its comprehensive insurance program. The current coverage year has an aggregate limit of US$575 million for pollution liability for the period from May 1, 2011 through April 30, 2012.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed 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. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at

December 31, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. 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.

29. GUARANTEES

In the normal course of conducting business, the Company enters into agreements which indemnify third parties. 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 these 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. Examples of such indemnification obligations include the following.

Sale Agreements for Assets or Businesses:

- breaches of representations, warranties or covenants;
- loss or damages to property;
- environmental liabilities;
- changes in laws;
- valuation differences;
- litigation; and
- contingent liabilities.

Provision of Services and Other Agreements:

- breaches of representations, warranties or covenants;
- changes in laws;
- intellectual property rights infringement; and
- litigation.

When disposing of assets or businesses, 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 above-noted 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.

30. SUBSEQUENT EVENT

On December 9, 2011 the Government of New Brunswick tabled and subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permitted the government to implement new regulations which could affect the franchise agreement between Enbridge Gas New Brunswick (EGNB) and the province, impact prior decisions by the province's independent regulator and influence the regulator's future decisions. However, significant details of the rate setting process were left to be established in the new regulations and, as such, the effect of such legislation was not determinable at that time.

A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick on April 16, 2012. Based on the amendments to the rate setting methodology outlined therein, EGNB will no longer meet the criteria for the continuation of rate regulated accounting. As a result, the Company must eliminate from its Consolidated Statement of Financial Position 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.

As the final rates and tariffs regulation published on April 16, 2012 provided further evidence of a condition that existed on December 31, 2011, recognition of the charge totaling $262 million, after tax, was reflected as a subsequent event in these U.S. GAAP consolidated financial statements. The charge reflects Management's best estimate based on facts available at this time and may be subject to further revision based on future actions or interpretations of the regulator, the Government of New Brunswick or other factors.

The discontinuance of rate regulated accounting for EGNB will result in future earnings being subject to increased variability, including quarterly seasonality, as there will be no further accumulation of the regulatory deferral account. Earnings will increase in the colder winter months when demand for natural gas is high and earnings will decrease in the warmer summer months when demand, and therefore delivered volumes, is low.

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. and EGNB, commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen's Bench, claiming damages in the amount of $650 million as a result of continuing breaches by the Province of the General Franchise Agreement that it signed with Enbridge in 1999. There is no assurance these actions will be successful or will result in any recovery.