Enbridge Inc.

ENB

Second Quarter
Interim Report to Shareholders
For the six months ended June 30, 2014

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars unless otherwise noted)

- Second quarter earnings were $756 million and six months earnings were $1,146 million, both including the impact of net unrealized non-cash mark-to-market gains and losses
- Second quarter and six months adjusted earnings were $328 million and $820 million, respectively, or $0.40 and $1.00 per common share, respectively
- Enbridge Inc. and Enbridge Energy Partners, L.P. announced an equity restructuring involving the General Partner's incentive distributions rights within Enbridge Energy Partners, L.P.
- Enbridge Inc. continued to execute its long-term funding plan and raised approximately $3.3 billion since the end of the first quarter through a combination of debt and equity issuances
- Marathon Petroleum Corporation named anchor shipper and equity partner in the US$0.9 billion Southern Access Extension Project, and will fund 35% of the project
- Ontario Energy Board approved Enbridge Gas Distribution Inc. five-year incentive rate application
- Northern Gateway Project approved by the Government of Canada, subject to conditions

CALGARY, ALBERTA – August 1, 2014 – Enbridge Inc. (Enbridge or the Company) (TSX:ENB) (NYSE:ENB) – "Earnings for the first half of this year are in line with our expectations and our full year adjusted earnings per share guidance of $1.84 to $2.04 per share," said Al Monaco, President and Chief Executive Officer. "More broadly, we are keenly focused on the implementation of our strategic plan and on our key priorities of safety and operational reliability, execution of our growth projects and extending and diversifying our growth beyond 2017. The plan, which now includes a growth capital program of $42 billion, of which $37 billion is commercially secured and expected to be put into service by 2017, gives us continued confidence in delivering average annual earnings per share growth of 10-12% through 2017, and there are a number of factors that bode very well for post 2017 growth.

"In Liquids Pipelines, our largest business, our strategy is driven by our customers' need for incremental pipeline capacity and new market access to accommodate the continued strong growth of North American supply," said Mr. Monaco. "Market access remains a strategic imperative and we are making good progress. Construction of the Seaway Twin is now mechanically complete and we expect to complete the Flanagan South project this fall, adding an incremental 600,000 barrels per day of heavy crude capacity to the key refining hub in the U.S. Gulf Coast. By the end of 2016, we expect to bring into service projects that will open up approximately 1.7 million barrels per day of incremental capacity."

Enbridge remained active in the capital markets. Since the end of the first quarter, Enbridge has raised approximately $0.5 billion through a public common share offering. Proceeds from the offering will be used to fund the incremental capital required for the Line 3 Replacement Program and other general corporate purposes. In addition, the Company raised approximately $0.9 billion in cumulative redeemable preference shares, US$1.5 billion in senior notes and $0.3 billion in medium-term notes.

Effective July 1, 2014, Enbridge and Enbridge Energy Partners, L.P. (EEP) restructured the equity in EEP under which Enbridge as the General Partner (GP) of EEP will permanently waive its existing incentive distribution rights (IDR) in exchange for Class D units and new incentive distribution units (IDU). The GP share of incremental cash distributions will also decrease from 48% of all distributions in excess of US$0.4950 per unit per quarter down to 23% of all distributions in excess of the EEP's current quarterly distribution of US$0.5435 per unit per quarter. The restructuring is intended to enhance the economics of EEP's investment projects and growth opportunities, while at the same time re-establishing EEP as a strong sponsored vehicle and as an effective source of funding for Enbridge via future drop downs.

"This restructuring builds upon steps we initiated last year to re-establish EEP as a cost effective sponsored vehicle for Enbridge," said Mr. Monaco. "A stronger EEP supports Enbridge's strategic priorities of executing our growth capital program and extending growth beyond 2017."

On July 1, 2014, EEP completed a drop down of additional interest in the natural gas and natural gas liquids (NGL) midstream business to Midcoast Energy Partners, L.P. (MEP) for cash proceeds of US$350 million, the first drop down of additional interests since the initial public offering of MEP units. As a new low cost funding vehicle, these drop downs to MEP improve EEP's funding effectiveness and are another step to re-establishing EEP as a strong sponsored vehicle for Enbridge.

On June 17, the Canadian federal government approved the Northern Gateway Project (Northern Gateway). This approval comes after the most comprehensive review of a pipeline project in Canadian history and is subject to Northern Gateway meeting the 209 conditions issued by the Joint Review Panel (JRP).

"The federal government's approval supports Enbridge's view that the project can be built and operated safely, and that opening up new markets for Canadian energy is in our national interest," said Mr. Monaco. "That said, we still have a lot of work to do. We will continue to focus on three priorities: meeting the JRP's conditions; working with the Province of British Columbia on its five conditions for supporting oil pipelines; and continuing to engage Aboriginal communities to build further trust and support."

Effective July 28, 2014, the Enbridge Board appointed as a director Marcel R. Coutu. Mr. Coutu is the past Chairman of Syncrude Canada Ltd., an integrated oil sands project, and the former President and Chief Executive Officer of Canadian Oil Sands Limited. He is currently a director of Brookfield Asset Management, Power Corporation of Canada, The Great-West Lifeco Inc. and IGM Financial Inc., as well as the Calgary Exhibition and Stampede Board, a non-profit organization.

Also in the second quarter, Enbridge announced that J. Richard Bird, Executive Vice President, Chief Financial Officer and Corporate Development, will retire by the end of the 2014. Upon his retirement, Mr. Bird's role will be split into two roles: Chief Financial Officer and Chief Development Officer. In the interim, effective July 1, 2014, John Whelen has been appointed to the role of Senior Vice President, Finance, and Vern Yu has been appointed as Senior Vice President, Corporate Development.

"Richard has been a force at Enbridge for more than 20 years and has made a significant contribution to the Company's success. While he will unquestionably be missed, our leadership succession process ensures that we have highly qualified individuals who are ready to fill critical senior roles in the Company," said Mr. Monaco. "Richard will be supporting John and Vern in their new roles for the remainder of the year and we're confident that his disciplined approach will carry forward."

Results of Operations

Enbridge second quarter adjusted earnings increased by 5% to $0.40 per common share and remained at $1.00 per common share for the first half of 2014 compared with the respective 2013 comparative periods. The results were in line with management's expectation, matching the prior year's exceptionally strong first half. The Company remains on track to achieve its 2014 full year adjusted earnings per share guidance range.

Second quarter adjusted earnings growth was primarily driven in Liquids Pipelines and bolstered by strong supply from western Canada and increased downstream refinery demand leading to higher throughput on the Canadian Mainline. Likewise, higher throughput was also achieved on the Athabasca mainline in the Company's Regional Oil Sands System, which also benefitted from contributions from new projects coming into service, in particular the Norealis Pipeline.

Another key driver to the Company's second quarter growth was contributions from the Company's sponsored vehicles, as both EEP and Enbridge Income Fund (the Fund) delivered a second consecutive quarter of strong performance. EEP adjusted earnings growth was supported by higher throughput and tolls across the majority of its liquids pipeline assets. Earnings from the Fund also reflected strong results from its liquids business, in particular, the Saskatchewan System.

Enbridge Gas Distribution Inc. (EGD) continued to contribute to Enbridge's reliable business model although the second quarter results were lower than the comparable period due to an increase in depreciation expense from an increased asset base and higher interest expense. EGD operated in the first half of 2014 under interim distribution rates pending approval of a five-year customized Incentive Rate (IR) application by the Ontario Energy Board (OEB). With the approval granted in July 2014, the difference in revenues under the interim rates and rates under the customized IR application will be adjusted as part of EGD's October 2014 Quarterly Rate Adjustment Mechanism process.

Energy Services second quarter adjusted earnings were unfavourable compared with the exceptionally strong second quarter of 2013 and reflected narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, with associated unrecovered demand charges.

The adjusted earnings discussed above excludes the impact of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains and losses from the Company's long-term hedging program, gains on the disposal of non-core assets and investments, as well as certain costs and related insurance recoveries arising from crude oil releases. See *Non-GAAP Measures.*

SECOND QUARTER 2014 OVERVIEW

For more information on Enbridge's growth projects and operating results, please see the Management's Discussion and Analysis (MD&A) which is filed on SEDAR and EDGAR and also available on the Company's website at www.enbridge.com/InvestorRelations.aspx.

- Earnings attributable to common shareholders increased from $42 million in the second quarter of 2013 to $756 million in the second quarter of 2014. The Company delivered strong quarter-over-quarter earnings growth, however, the magnitude of this growth and the comparability of the Company's quarterly results are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports reliable cash flows and dividend growth. Other non-recurring factors impacting quarter-over-quarter comparability were remediation and long-term stabilization costs of approximately $40 million after-tax and before insurance recoveries recorded in the second quarter of 2013 related to the Line 37 crude oil release which occurred in June 2013.

- Enbridge's adjusted earnings increased from $306 million in the second quarter of 2013 to $328 million in the second quarter of 2014. Liquids Pipelines adjusted earnings reflected higher contributions from Canadian Mainline and Regional Oil Sands System. Canadian Mainline adjusted earnings reflected higher throughput partially offset by the absence of revenues from Line 9B. Within Regional Oil Sands System, higher adjusted earnings were primarily attributable to higher throughput on the Athabasca mainline and contributions from the Norealis Pipeline. In Gas Distribution, EGD's lower adjusted earnings reflected a gas transportation cost adjustment related to the first half of 2013 which was recorded in the third quarter of 2013 and higher depreciation expense due to the growth in asset base and higher interest expense. Energy Services adjusted earnings declined in the second quarter of 2014 compared with an exceptionally strong comparative 2013 period due to narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity. Both the Company's sponsored vehicles, EEP and the Fund, contributed to the adjusted earnings increase and reflected strong results from their core assets. EEP adjusted earnings reflected higher contributions from the majority of its liquids business through higher throughput and tolls as well as the positive contribution from new assets placed into service. Adjusted earnings for the Fund also reflected higher earnings from its liquids business, in particular the Saskatchewan System.

- On July 17, 2014, the OEB approved EGD's five-year customized IR application, with modifications. The customized IR application establishes the methodology for establishing rates for the distribution of natural gas over a five-year period from 2014 through 2018 and will allow EGD to recover its capital investment amounts, as well as an opportunity to earn above the allowed return on equity. The OEB decision also allows for final 2014 rates to be implemented with the October 2014 Quarterly Rate Adjustment Mechanism with an effective date of January 1, 2014. EGD is currently operating under OEB approved interim distribution rates. The difference in revenues under the interim rates and rates under the customized IR will be adjusted as part of the October 2014 Quarterly Rate Adjustment Mechanism process.

- On July 1, 2014, Enbridge and EEP completed the equity restructuring, which was agreed to on June, 18, 2014, under which Enbridge Energy Company, Inc., a wholly owned subsidiary of Enbridge and the GP of EEP, irrevocably waived its then existing IDR in excess of its 2% GP interest in exchange for 66.1 million Class D units and 1,000 IDU (collectively, the Equity Restructuring). The Class D units carry a distribution equal to the quarterly distribution on the Class A common units. The third quarter 2014 distribution on the Class D units will be adjusted to provide Enbridge with an aggregate distribution in 2014 equal to the distribution on its IDR as if the Equity Restructuring had not occurred. The IDU will not be entitled to a distribution initially, but will in the future be entitled to 23% of any amount in excess of EEP's current quarterly Class A common unit distribution of US$0.5435 per unit. In the event of any decrease in the Class A common unit distribution below US$0.5435 per unit in any quarter during the next five years, the distribution on the Class D units will be reduced to the amount which would have been received by Enbridge under the existing IDR as if the Equity Restructuring had not occurred.

- Also on July 1, 2014, Enbridge and Marathon Petroleum Corporation (MPC) reached an agreement to admit MPC as a 35% equity interest partner in the Southern Access Extension project (Southern Access Extension). MPC will also make additional cash contributions in accordance with the Southern Access Extension spend profile in proportion to its 35% interest. The Southern Access Extension was announced as part of Enbridge's Light Oil Market Access Program in December 2012 and will involve the construction of a new 265-kilometre (165-mile) 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, for an initial capacity of approximately 300,000 barrels per day, as well as additional tankage and two new pump stations. Subject to regulatory and other approvals, Southern Access Extension is expected to be placed into service in mid-2015 and Enbridge's share of the project is expected to be approximately US$0.6 billion.

- On June 18, 2014, Enbridge announced that J. Richard Bird, Executive Vice President, Chief Financial Officer and Corporate Development, plans to retire by the end of 2014. Upon Mr. Bird's retirement, his responsibilities will be split into two separate roles of Chief Financial Officer and Chief Development Officer. Enbridge also announced the appointment of John Whelen as Senior Vice President, Finance and Vern Yu as Senior Vice President, Corporate Development, effective July 1, 2014.

- Since the end of the first quarter of 2014, the Company completed the following financing transactions:
    - On July 17, 2014, Enbridge completed an offering of 14 million Cumulative Redeemable Preference Shares, Series 13 for gross proceeds of $350 million.
    - On June 24, 2014, Enbridge completed an offering of 7.9 million Common Shares for gross proceeds of approximately $400 million and on July 8, 2014 issued a further 1.2 million Common Shares pursuant to the underwriters' over-allotment option for gross process of approximately $60 million.
    - On June 4, 2014, Enbridge issued senior notes of US$500 million with a three-year maturity, US$500 million with a 10-year maturity and US$500 million with a 30-year maturity.
    - On May 22, 2014, Enbridge completed an offering of 20 million Cumulative Redeemable Preference Shares, Series 11, for gross proceeds of $500 million.

- On April 22, 2014, Enbridge issued medium-term notes of $300 million with a three-year maturity through its subsidiary EGD.

DIVIDEND DECLARATION

On July 29, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2014 to shareholders of record on August 15, 2014.

Common Shares	$0.35000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11[1]	$0.30740

1 This first dividend declared for the Preference Shares, Series 11 includes accrued dividends from May 22, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on December 1, 2014.

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2014

This Management's Discussion and Analysis (MD&A) dated July 31, 2014 should be read in conjunction with the unaudited interim consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three and six months ended June 30, 2014, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company's Annual Report for the year ended December 31, 2013. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

CONSOLIDATED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**431**	(67)	**475**	80
Gas Distribution	**19**	27	**155**	134
Gas Pipelines, Processing and Energy Services	**107**	160	**298**	189
Sponsored Investments	**87**	72	**171**	114
Corporate	**112**	(150)	**1**	(225)
Earnings attributable to common shareholders from continuing operations	**756**	42	**1,100**	292
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	-	**46**	-
Earnings attributable to common shareholders	**756**	42	**1,146**	292
Earnings per common share	**0.92**	0.05	**1.39**	0.37
Diluted earnings per common share	**0.91**	0.05	**1.38**	0.36

Earnings attributable to common shareholders were $756 million for the three months ended June 30, 2014, or $0.92 per common share, compared with $42 million or $0.05 per common share, for the three months ended June 30, 2013. The Company delivered strong quarter-over-quarter earnings growth, however, the magnitude of this growth and the comparability of the Company's quarterly results are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes over the long-term it supports reliable cash flows and dividend growth. Other non-recurring factors impacting quarter-over-quarter comparability were remediation and long-term stabilization costs of approximately $40 million after-tax and before insurance recoveries recorded in the second quarter of 2013 related to the Line 37 crude oil release which occurred in June 2013.

Earnings attributable to common shareholders were $1,146 million for the six months ended June 30, 2014, or $1.39 per common share, compared with $292 million, or $0.37 per common share, for the six months ended June 30, 2013. In addition to the trends experienced in the three month period discussed above, earnings for the six months ended June 30, 2014 reflected a $43 million after-tax gain recognized on the disposal of non-core assets within Enbridge Offshore Pipelines (Offshore) and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment. Also impacting the comparability between the two periods were accruals related to the Line 6B crude oil release. For the six months ended June 30, 2014, the Company recognized an accrual of US$35 million ($5 million after-tax attributable to Enbridge) compared with US$215 million ($30 million after-tax attributable to Enbridge) for the six months ended June 30, 2013. Also reflected in earnings for the first half of 2013 was US$42 million ($6 million after-tax attributable to Enbridge) of insurance recoveries recognized as a reduction to environmental costs for the Line 6B crude oil release. For discussion on Line 6B leak remediation costs and associated insurance recoveries refer to *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.*

FORWARD-LOOKING INFORMATION

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

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

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

NON-GAAP MEASURES

This MD&A contains references to adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments. Adjusting items referred to as changes in unrealized derivative fair value gains or loss are presented net of amounts realized on the settlement of derivative contracts during the applicable period. Management believes the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, including setting the Company's dividend payout target, and to assess the performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See Non-GAAP Reconciliations *for a reconciliation of the GAAP and non-GAAP measures.*

ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**220**	159	**438**	378
Gas Distribution	**15**	25	**118**	138
Gas Pipelines, Processing and Energy Services	**27**	73	**86**	132
Sponsored Investments	**96**	71	**180**	138
Corporate	**(30)**	(22)	**(2)**	8
Adjusted earnings	**328**	306	**820**	794
Adjusted earnings per common share	**0.40**	0.38	**1.00**	1.00

Adjusted earnings were $328 million, or $0.40 per common share, for the three months ended June 30, 2014 compared with $306 million, or $0.38 per common share, for the three months ended June 30, 2013. Adjusted earnings were $820 million, or $1.00 per common share, for the six months ended June 30, 2014 compared with $794 million, or $1.00 per common share, for the six months ended June 30, 2013.

The following factors impacted adjusted earnings:

- Within Liquids Pipelines, higher throughput on Canadian Mainline drove an increase in adjusted earnings. The increase in throughput was attributable to several factors: increased oil sands production; volumes diverted from competing systems; strong refinery demand in the midwest market partly due to a start-up of a midwest refinery's conversion to heavy oil processing in the second quarter of 2014; and successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Canadian Mainline adjusted earnings continued to be impacted by the absence of revenues from Line 9B, which was idled in late 2013. As part of the Company's Eastern Access initiative, Line 9B is being reversed and expanded and is expected to return to service in the fourth quarter of 2014.
- Also within Liquids Pipelines, Regional Oil Sands System adjusted earnings increased due to contributions from the Norealis Pipeline, which was completed in April 2014, and higher throughput on the Athabasca mainline which were partially offset by higher operating and administrative, depreciation, interest and tax expenses.
- Within Gas Distribution, Enbridge Gas Distribution Inc.'s (EGD) lower adjusted earnings primarily reflected a gas transportation cost adjustment related to the first half of 2013 which was recorded in the third quarter of 2013. Excluding the impact of the gas transportation adjustment, EGD's results were moderately lower and reflected higher depreciation expense due to the growth in asset base.
- Within Gas Pipelines, Processing and Energy Services, the decrease in adjusted earnings reflected lower Energy Services results compared with an exceptionally strong second quarter and first half of 2013. Narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity resulted in lower adjusted earnings in the second quarter of 2014.

For the six months ended June 30, 2014, in addition to the second quarter trends noted above, adjusted earnings decreased as a result of losses realized on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. Partially offsetting the decrease in adjusted earnings within Energy Services in the first half of 2014 were favourable natural gas location differentials caused by abnormal winter weather conditions in the first quarter of 2014.

- Within Sponsored Investments, Enbridge Energy Partners, L.P. (EEP) adjusted earnings reflected increased contributions from EEP's liquids business due to higher throughput and tolls, as well as contributions from new assets placed into service. Partially offsetting these positive contributions were lower volumes within EEP's natural gas and NGL businesses.
- Also within Sponsored Investments, Enbridge Income Fund (the Fund) earnings reflected strong performance in the Fund's liquids business, in particular the Saskatchewan System during the second quarter of 2014 and the Bakken Expansion Pipeline during the first quarter of 2014. Also contributing to period-over-period growth in earnings for the first half of 2014 was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013.
- Within the Corporate segment, Noverco Inc. (Noverco) adjusted earnings decreased in the first half of 2014 due to the impact of a small one-time gain on a sale of an investment and an equity earnings true-up adjustment, both of which were captured in the first quarter of 2013. Excluding the impacts of these two items, Noverco adjusted earnings were comparable between periods.
- Also within Corporate segment, a higher Other Corporate loss was recognized in the second quarter of 2014 due to higher preference share dividends from an increase in the number of preference shares outstanding, partially offset by lower net Corporate segment financing costs.

RECENT DEVELOPMENTS

CHIEF FINANCIAL OFFICER SUCCESSION PLANS

On June 18, 2014, the Company announced that J. Richard Bird, Executive Vice President, Chief Financial Officer and Corporate Development, plans to retire by the end of 2014. Upon Mr. Bird's retirement, his responsibilities will be split into two separate roles of Chief Financial Officer and Chief Development Officer. Enbridge also announced the appointment of John Whelen as Senior Vice President, Finance and of Vern Yu as Senior Vice President, Corporate Development effective July 1, 2014.

LIQUIDS PIPELINES

Seaway Pipeline

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011. Initially the Federal Energy Regulatory Commission (FERC) rejected the application in March 2012 and Seaway Pipeline appealed to the District of Columbia Circuit. In response, the FERC set the application for further proceedings and the appeal was stayed. Since the FERC had not issued a ruling on this application, Seaway Pipeline filed for initial rates in order to have rates in effect by the in-service date. The uncommitted rate on Seaway Pipeline was challenged by several shippers. During the evidentiary stage, FERC staff filed evidence stating that the committed and uncommitted rates are subject to review and adjustment. Seaway Pipeline filed a Petition for Declaratory Order (PDO) requesting the FERC confirm that it will honour and uphold existing contracts. The FERC issued a decision denying the PDO on procedural grounds but stated that it will uphold its longstanding policy of honouring contracts.

FERC hearings concluded with all parties filing their respective briefs. In September 2013, a decision from the Administrative Law Judge (ALJ) was released finding that the committed and uncommitted rates on Seaway Pipeline should be reduced to reflect the ALJ's findings on the various cost of service inputs. Seaway Pipeline filed a brief with the FERC on October 15, 2013 challenging the ALJ's decision and asking for expedited ruling by the FERC on the committed rates. In February 2014, the FERC issued its decision upholding its policy to honour contracts and ordered the ALJ to revise its decision accordingly. On May 9, 2014, the ALJ issued an initial decision on remand reiterating its previous findings and did not change its decision. Briefings have concluded and the full record will be sent to the FERC for its final decision. It is expected that the FERC's decision will be expedited.

In relation to the original market based rate application, the FERC issued its decision rejecting Seaway Pipeline's application for market based rates in February 2014 and announced a new methodology for determining whether a pipeline has market power and invited Seaway Pipeline to refile its market based rate application consistent with the new policy. Seaway Pipeline is currently evaluating whether it will file a new market based rate application under the new methodology.

GAS DISTRIBUTION

Enbridge Gas Distribution – Incentive Regulation

On July 17, 2014, the Ontario Energy Board (OEB) approved EGD's five-year customized Incentive Rate (IR) application, with modifications. The customized IR application establishes the methodology for establishing rates for the distribution of natural gas over a five-year period from 2014 through 2018 and will allow EGD to recover its capital investment amounts, as well as an opportunity to earn above the allowed return on equity. The OEB decision also allows for final 2014 rates to be implemented with the October 2014 Quarterly Rate Adjustment Mechanism with an effective date of January 1, 2014. EGD is currently operating under OEB approved interim distribution rates. The difference in revenues under the interim rates and rates under the customized IR will be adjusted as part of the October 2014 Quarterly Rate Adjustment Mechanism process on a prospective basis.

Enbridge Gas New Brunswick – Regulatory Matter

In 2012, the Government of New Brunswick enacted final rates and tariff regulation that affected the franchise agreement between Enbridge Gas New Brunswick Inc. (EGNB) and the province of New Brunswick, including the ability for EGNB to recover a deferred regulatory asset.

Also in 2012, EGNB commenced legal proceedings against the Government of New Brunswick seeking damages for breach of contract and commenced a separate application to quash the Government of New Brunswick's rate and tariffs regulation. EGNB's appeal was ultimately successful in part, as the Court of Appeal ruled that the rates and tariffs regulation that caps rates according to a maximum revenue-to-cost ratio was beyond the regulation-making authority of the New Brunswick Lieutenant Governor in Council. The Court upheld the portion of the regulation that requires EGNB to charge customers the lower of market or cost-based rates. Following a series of decisions by the New Brunswick Energy and Utilities Board that enabled EGNB to recover its revenue requirement from August 2013 to the next rate period, EGNB filed its 2014 rate application in October 2013. The application was approved in April 2014.

On February 4, 2014, EGNB commenced a further legal proceeding against the Government of New Brunswick. The action seeks damages for improper extinguishment of the deferred regulatory asset that was previously eliminated from EGNB's Consolidated Statements of Financial Position.

There is no assurance that any of EGNB's legal proceedings against the Province of New Brunswick will be successful or will result in any recovery.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge Energy Partners, L.P. Equity Restructuring

In June 2014, EEP and Enbridge announced an agreement to restructure EEP's equity with the objective of enhancing the economics of EEP's investment projects and growth opportunities, while at the same time re-establishing EEP as a strong sponsored vehicle and as an effective source of funding for Enbridge via future drop downs.

Effective July 1, 2014, Enbridge Energy Company, Inc., a wholly owned subsidiary of Enbridge and the General Partner (GP) of EEP, irrevocably waived its then existing incentive distribution rights (IDR) in excess of its 2% GP interest in exchange for 66.1 million Class D units and 1,000 Incentive Distribution Units (IDU) (collectively, the Equity Restructuring). The GP share of incremental cash distributions will also decrease from 48% of all distributions in excess of US$0.4950 per unit per quarter down to 23% of all distributions in excess of EEP's quarterly distribution of US$0.5435 per unit per quarter. The Class D units carry a distribution equal to the quarterly distribution on the Class A common units. The third quarter 2014 distribution on the Class D units will be adjusted to provide Enbridge with an aggregate distribution in 2014 equal to the distribution on its IDR as if the Equity Restructuring had not occurred. The IDU will not be entitled to a distribution initially and in the event of any decrease in the Class A common unit distribution below US$0.5435 per unit in any quarter during the next five years, the distribution on the Class D units will be reduced to the amount which would have been received by Enbridge under the existing IDR as if the Equity Restructuring had not occurred.

The Class D units have a notional value per unit equivalent to the closing market price of the Class A Common units on June 17, 2014 (Notional Value) and have the same voting rights as the Class A units. The Class D units are convertible on a one-for-one basis into Class A common units at any time on or after the fifth anniversary of the closing date, at the holder's option. In the event of a liquidation event (or any merger or other extraordinary transaction), the Class D unitholders will have a preference in liquidation equal to 20% of the Notional Value, with such preference being increased by an additional 20% on each anniversary of the closing date, resulting in a liquidation preference equal to 100% of the Notional Value on the fourth anniversary of the closing date. The Class D units will be redeemable in 30 years in whole or in part at EEP's option for either a cash amount equal to the Notional Value per unit or newly issued Class A common units with an aggregate market value at redemption equal to 105% of the aggregate Notional Value of the Class D units being redeemed.

EEP Drop Down of Additional Interest to Midcoast Energy Partners, L.P.
On July 1, 2014, EEP completed the sale of an additional 12.6% limited partnership interest in its natural gas and NGL midstream business to Midcoast Energy Partners, L.P. (MEP) for cash proceeds of US$350 million. Since finalization of this transaction, EEP held an approximate 48% direct interest in entities or partnerships holding the natural gas and NGL midstream operations, with the remaining ownership held by MEP. The balance of EEP’s interest in the natural gas and NGL midstream operations is held indirectly through ownership of a GP interest, an approximate 52% limited partner interest and all incentive distribution rights of MEP. The completion of this transaction resulted in a partial monetization of EEP’s natural gas and NGL midstream business through sale to noncontrolling interests (being MEP’s public unitholders). The proceeds from the drop down provided EEP a cost-effective funding alternative to execute its current liquids pipeline organic growth program.

Line 6B Crude Oil Release
EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013 and again on May 1, 2013 based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. At this time, EEP has completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta.

EEP is also working with the Michigan Department of Environmental Quality (MDEQ) to transition submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities from the EPA to the MDEQ, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at June 30, 2014, EEP’s total cost estimate for the Line 6B crude oil release was US$1,157 million ($186 million after-tax attributable to Enbridge), which is an increase of US$35 million ($5 million after-tax attributable to Enbridge) as compared with December 31, 2013 and March 31, 2014. On May 28, 2014, the MDEQ’s Water Resource Division approved EEP’s Schedule of Work for the remainder of 2014. Approximately US$30 million of the increase in the total cost estimate during the three months ended

June 30, 2014 is primarily related to the finalization of the MDEQ approved Schedule of Work and other costs related to the on-going river restoration activities near Ceresco.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at June 30, 2014. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews throughout the year. On May 1 of each year, the insurance program is up for renewal and includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents excluding costs for fines and penalties.

A majority of the costs incurred in connection with 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. Including EEP's remediation spending through June 30, 2014, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at June 30, 2014, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers for the then remaining US$145 million coverage, as one particular insurer is disputing the recovery eligibility for costs related to EEP's claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of the recovery from that insurer. EEP received a partial recovery payment of US$42 million from the other remaining insurers. Of the remaining US$103 million coverage limit, US$85 million is the subject matter of the lawsuit Enbridge filed in March 2013 against one particular insurer who is disputing EEP's recovery eligibility for costs related to its claim on the Line 6B oil release. The recovery of the remaining US$18 million is awaiting resolution of this lawsuit. While EEP believes those costs are eligible for recovery, there can be no assurance that EEP will prevail in this lawsuit.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2015 with a liability aggregate limit of US$700 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events was increased to US$30 million per event, from the previous US$10 million. In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 17 actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material.

As at June 30, 2014, included in EEP's estimated costs related to the Line 6B crude oil release is US$30 million in fines and penalties. Due to the absence of sufficient information, EEP cannot provide a reasonable estimate of the liability for potential additional fines and penalties that could be assessed in connection with the Line 6B release. Discussions with governmental agencies regarding fines and penalties are ongoing.

CORPORATE

Preference Share Issuance

Series 9

On March 13, 2014, the Company issued 11 million Preference Shares, Series 9 for gross proceeds of $275 million. The 4.4% Cumulative Redeemable Preference Shares, Series 9 are entitled to receive a fixed, cumulative, quarterly preferential dividend of $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on December 1, 2019 and on December 1 of every fifth year thereafter. The holders of Preference Shares, Series 9 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 10, subject to certain conditions, on December 1, 2019 and on December 1 of every fifth year thereafter. The holders of Preference Shares, Series 10 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Series 11

On May 22, 2014, the Company issued 20 million Preference Shares, Series 11 for gross proceeds of $500 million. The 4.4% Cumulative Redeemable Preference Shares, Series 11 are entitled to receive a fixed, cumulative, quarterly preferential dividend of $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on March 1, 2020 and on March 1 of every fifth year thereafter. The holders of Preference Shares, Series 11 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 12, subject to certain conditions, on March 1, 2020 and on March 1 of every fifth year thereafter. The holders of Preference Shares, Series 12 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.6%.

Series 13

On July 17, 2014, the Company issued 14 million Preference Shares, Series 13 for gross proceeds of $350 million. The 4.4% Cumulative Redeemable Preference Shares, Series 13 are entitled to receive a fixed, cumulative, quarterly preferential dividend of $1.10 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for $25.00 per share plus all accrued and unpaid dividends on June 1, 2020 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 13 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 14, subject to certain conditions, on June 1, 2020 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 14 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.7%.

Common Share Issuance

On June 24, 2014, the Company completed the issuance of 7.9 million Common Shares for gross proceeds of approximately $400 million and on July 8, 2014, issued a further 1.2 million Common Shares pursuant to the underwriters' over-allotment option for gross proceeds of approximately $60 million. The proceeds will be used to partially fund the Company's capital projects, including the Line 3 Replacement Program (L3R Program), to reduce short term indebtedness and for other general corporate purposes. For further discussion on the L3R Program refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Canadian Line 3 Replacement Program* and *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – United States Line 3 Replacement Program*.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

The table below summarizes the current status of the Company's commercially secured projects, organized by business segment.

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Seaway Crude Pipeline System Twinning/Extension	US$1.2 billion	US$1.1 billion	2014	Substantially complete
2. Eastern Access Line 9 Reversal and Expansion	$0.7 billion	$0.4 billion	2013-2014 (in phases)	Under construction
3. Eddystone Rail Project	US$0.1 billion	US$0.1 billion	2014	Complete
4. Norealis Pipeline	$0.5 billion	$0.5 billion	2014	Complete
5. Flanagan South Pipeline Project	US$2.8 billion	US$2.5 billion	2014	Under construction
6. Canadian Mainline Expansion	$0.7 billion	$0.2 billion	2015	Under construction
7. Surmont Phase 2 Expansion	$0.3 billion	$0.1 billion	2014-2015 (in phases)	Under construction
8. Athabasca Pipeline Twinning	$1.2 billion	$0.9 billion	2015[3]	Under construction
9. Edmonton to Hardisty Expansion	$1.8 billion	$0.5 billion	2015	Under construction
10. Southern Access Extension	US$0.6 billion	US$0.1 billion	2015	Pre-construction
11. AOC Hangingstone Lateral	$0.1 billion	No significant expenditures to date	2015	Pre-construction
12. Sunday Creek Terminal Expansion	$0.2 billion	$0.1 billion	2015	Under construction
13. Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.2 billion	2013-2015 (in phases)	Under construction
14. Woodland Pipeline Extension	$0.6 billion	$0.2 billion	2015	Under construction
15. JACOS Hangingstone Project	$0.1 billion	No significant expenditures to date	2016	Pre-construction
16. Wood Buffalo Extension	$1.6 billion	No significant expenditures to date	2017	Pre-construction
17. Norlite Pipeline System[4]	$1.4 billion	No significant expenditures to date	2017	Pre-construction
18. Canadian Line 3 Replacement Program	$4.9 billion	$0.1 billion	2017	Pre-construction
GAS DISTRIBUTION				
19. Greater Toronto Area Project	$0.7 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
20. Pipestone and Sexsmith Project	$0.3 billion	$0.3 billion	2012-2014 (in phases)	Complete
21. Blackspring Ridge Wind Project	$0.3 billion	$0.3 billion	2014	Complete
22. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-2015 (in phases)	Under construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
23. Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2015	Under construction
24. Keechi Wind Project	US$0.2 billion	US$0.1 billion	2015	Under construction
25. Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
SPONSORED INVESTMENTS				
26. EEP - Line 6B 75-Mile Replacement Program	US$0.4 billion	US$0.4 billion	2013-2014 (in phases)	Complete
27. EEP - Eastern Access[5]	US$2.7 billion	US$1.8 billion	2013-2016 (in phases)	Under construction
28. EEP - Lakehead System Mainline Expansion[5]	US$2.3 billion	US$0.5 billion	2014-2016 (in phases)	Under construction
29. EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	No significant expenditures to date	2015	Under construction
30. EEP - Sandpiper Project[6]	US$2.6 billion	US$0.2 billion	2016	Pre-construction
31. EEP - U.S. Line 3 Replacement Program	US$2.6 billion	No significant expenditures to date	2017	Pre-construction

1 These amounts are estimates and subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect Enbridge's share of joint venture projects.
2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to June 30, 2014.
3 The Athabasca Pipeline Twinning is now expected to be delayed beyond its original in service date due to a change in the construction schedule to align with the shipper volume availability.
4 Enbridge will construct and operate the Norlite Pipeline System. Keyera Corp. will fund 30% of the project.
5 The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP.
6 Enbridge will construct and operate the Sandpiper Project. Marathon Petroleum Corporation will fund 37.5% of the project.

LIQUIDS PIPELINES

Seaway Crude Pipeline System

Enbridge holds a 50% interest in the Seaway Pipeline which includes an 805-kilometre (500-mile) 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas.

Reversal and Expansion

The flow direction of the Seaway Pipeline was reversed in 2012, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. Further pump station additions and modifications were completed in 2013, increasing capacity available to shippers to up to approximately 400,000 barrels per day (bpd), depending on crude oil slate.

Twinning and Extension

A second line to more than double the existing capacity of the Seaway Pipeline to approximately 850,000 bpd was mechanically completed in July 2014. This 30-inch diameter pipeline follows the same route as the existing Seaway Pipeline and was constructed to meet additional capacity commitments from shippers. Included in the project scope is the 105-kilometre (65-mile), 36-inch diameter pipeline lateral from the Seaway Jones Creek facility southwest of Houston, Texas to Enterprise Product Partners L.P.'s ECHO crude oil terminal (ECHO Terminal) in Houston, Texas. The lateral was placed into service in January 2014.

In addition, a 161-kilometre (100-mile) pipeline is being constructed from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining centre to provide shippers access to the region's heavy oil refining capabilities. This extension will provide capacity of 750,000 bpd and was substantially completed in July 2014.

Including the acquisition of the initial 50% interest, Enbridge's total expected cost for the Seaway Pipeline is now approximately US$2.5 billion. The acquisition, reversal and expansion were completed at an approximate cost of US$1.3 billion, with the twinning, extension and lateral components of the project expected to cost approximately US$1.2 billion. Total expenditures incurred to date are approximately US$2.4 billion.

Eastern Access

The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects being undertaken by Enbridge include a partial reversal of Line 9A, a full reversal and expansion of Line 9B and expansion of the Toledo Pipeline. For discussion on EEP's portion of Eastern Access refer to *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Eastern Access*.

In 2013, Enbridge completed the 80,000 bpd expansion of its Toledo Pipeline (Line 17), which connects with the EEP mainline at Stockbridge, Michigan and serves refineries at Toledo, Ohio and Detroit, Michigan. The project was completed at an approximate cost of US$0.2 billion.

In 2013, Enbridge also completed the reversal of a portion of its Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario. Enbridge is also undertaking a full reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec. The Line 9B reversal was expected to be completed at an estimated cost of approximately $0.3 billion. Following an open season held on the Line 9B reversal project, further commitments were received that required additional delivery capacity within Ontario and Quebec, resulting in the Line 9B capacity expansion project. The Line 9B capacity expansion will increase the annual capacity of Line 9B from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion.

Both the Line 9B reversal and Line 9B capacity expansion projects were approved by the National Energy Board (NEB) in March 2014 subject to 30 conditions. The conditions imposed by the NEB, including costs associated with additional NEB mandated integrity testing increased the total expected cost of the projects to $0.7 billion, inclusive of costs related to the previously discussed Line 9A reversal. Enbridge is currently in discussions with shippers to recover the incremental costs of Line 9B through tolls. Subject to fulfillment of the NEB conditions, both projects are expected to be available for service in the fourth quarter of 2014. Total expenditures to date on the Line 9A and Line 9B projects are approximately $0.4 billion.

Eddystone Rail Project

In April 2014, under a joint venture agreement with Canopy Prospecting Inc., the Company completed the development of a unit-train unloading facility and related local pipeline infrastructure near Philadelphia, Pennsylvania to deliver Bakken and other light sweet crude oil to Philadelphia area refineries. The Eddystone Rail Project (Eddystone) included leasing portions of a power generation facility and involved replacing and twinning the existing track to accommodate 120-car unit-trains, installing crude oil offloading equipment, refurbishing an existing 200,000 barrel tank and upgrading an existing barge loading facility. Eddystone is capable of receiving and delivering an initial capacity of 80,000 bpd, and could be expanded to 160,000 bpd. Based on its 75% joint venture interest, Enbridge's investment in the project was approximately US$0.1 billion.

Norealis Pipeline

In order to provide pipeline and terminalling services to the Husky Energy Inc. operated Sunrise Energy Project that is currently under development, Enbridge constructed a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline from the Norealis Terminal to the Cheecham Terminal and additional tankage at Cheecham. The Norealis Pipeline project was completed in April 2014 at a total cost of approximately $0.5 billion. Enbridge expects to receive first oil in the second half of 2014, commensurate with the start-up of the Sunrise Energy project.

Flanagan South Pipeline Project

The 950-kilometre (590-mile) Flanagan South Pipeline (Flanagan South) will have an initial design capacity of approximately 600,000 bpd; however, in the initial years it is not expected to operate at its full design capacity. Flanagan South will transport crude oil from the Company's terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline is being installed adjacent to the Company's Spearhead Pipeline for the majority of the route. Flanagan South is expected to be mechanically complete by mid-October 2014. The estimated cost of the project is approximately US$2.8 billion, with expenditures to date of approximately US$2.5 billion.

The Sierra Club and National Wildlife Federation (the Plaintiff) filed a complaint for Declaratory and Injunctive Relief (the Complaint) with the United States District Court for the District of Columbia (the Court) in August 2013. The Complaint was filed against multiple federal agencies (the Defendants) and included a request that the Court issue a preliminary injunction suspending previously granted federal permits and ordering Enbridge to discontinue construction of the project on the basis that the Defendants failed to comply with environmental review standards of the National Environmental Protection Act. Enbridge obtained intervener status and joined the Defendants in filing a response in opposition to the motion for preliminary injunction in September 2013. The Plaintiff's request for preliminary injunction was denied by the Court in November 2013. A court hearing was held on February 21, 2014 concerning the merits of the Complaint against the federal agencies, but no decision has yet been released.

Canadian Mainline Expansion

Enbridge is undertaking an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consists of two phases which involve the addition of pumping horsepower to raise the capacity of the Alberta Clipper line from 450,000 bpd to 800,000 bpd. The initial phase to increase capacity from 450,000 bpd to 570,000 bpd is expected to be substantially complete in September 2014 at an estimated capital cost of approximately $0.2 billion. Delays in receipt of the applicable regulatory approvals on EEP's portion of the mainline system expansion are expected to delay the full operation of the first phase of the Canadian Mainline Expansion. However, a number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 bpd capacity increase. See *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Mainline Expansion*.

The second phase to increase capacity from 570,000 bpd to 800,000 bpd is expected to be placed into service in 2015. The second phase is expected to cost approximately $0.5 billion following the completion of a detailed engineering review conducted in the first quarter of 2014. The revised estimate reflected enhanced tanking, terminalling and connectivity to optimize pipeline operation at the full 800,000 bpd design capacity. The estimated cost of the entire expansion is approximately $0.7 billion, with expenditures to date of approximately $0.2 billion.

Surmont Phase 2 Expansion

The Company entered into a terminal services agreement with ConocoPhillips Canada Resources Corp. (ConocoPhillips) and Total E&P Canada Ltd. (the ConocoPhillips Partnership) to expand the Cheecham Terminal to accommodate incremental bitumen production from Surmont's Phase 2 expansion. The Company is constructing two new 450,000 barrel blend tanks and converting an existing tank from blend to diluent service. The expansion is expected to come into service in two phases, with the blended product system expected in the fourth quarter of 2014 and the diluent system expected in the first quarter of 2015. The estimated cost of the project is approximately $0.3 billion with expenditures to date of approximately $0.1 billion.

Athabasca Pipeline Twinning

This project involves twinning the southern section of the Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to provide additional capacity to serve expected oil sands growth in the Kirby Lake producing region. The expansion project, with an estimated cost of approximately $1.2 billion, and expenditures to date of approximately of $0.9 billion, will include 346 kilometres (215 miles) of 36-inch diameter pipeline adjacent to the existing Athabasca Pipeline right-of-way. The line is now expected to be delayed beyond its original in service date of 2015 due to a change in the construction schedule to align with shipper volume availability.

Edmonton to Hardisty Expansion
The Company is undertaking an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project will include 181 kilometres (112 miles) of new 36-inch diameter pipeline and will provide an initial capacity of approximately 570,000 bpd, expandable to 800,000 bpd. The new line is expected to generally follow the same route as Enbridge's existing Line 4 pipeline. Also included in the project scope are connections into existing infrastructure at the Hardisty Terminal and new terminal facilities in Edmonton which include five new 500,000 barrel tanks. The new pipeline is expected to be placed into service in the first quarter of 2015, with additional tankage requirements expected to be completed by the end of 2015 at an expected total cost of approximately $1.8 billion. Expenditures incurred to date are approximately $0.5 billion.

Southern Access Extension
The Southern Access Extension project (Southern Access Extension) will involve the construction of a new 265-kilometre (165-mile) 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, for an initial capacity of approximately 300,000 bpd, as well as additional tankage and two new pump stations. Effective July 1, 2014, the Company entered into an agreement with Lincoln Pipeline LLC (Lincoln), an affiliate of Marathon Petroleum Corporation (MPC), to, among other things, admit Lincoln as a partner and participate in Southern Access Extension. Lincoln has purchased a 35% equity interest in the project and will make additional cash contributions in accordance with the Southern Access Extension spend profile in proportion to its 35% interest. Subject to regulatory and other approvals, the project is expected to be placed into service in mid-2015. Southern Access Extension is expected to cost approximately US$0.9 billion with Enbridge's share of the estimated capital cost expected to be approximately US$0.6 billion. Enbridge's expenditures to date on the project is approximately US$0.1 billion.

AOC Hangingstone Lateral
The Company entered into an agreement with Athabasca Oil Corporation (AOC) to provide pipeline and terminalling services to the proposed AOC Hangingstone Oil Sands Project (AOC Hangingstone) in Alberta. Phase I of the project will involve the construction of a new 49-kilometre (31-mile) 16-inch diameter pipeline from the AOC Hangingstone project site to Enbridge's existing Cheecham Terminal, and related facility modifications at Cheecham. Phase I of the project will provide an initial capacity of 16,000 bpd and is expected to be placed into service in the third quarter of 2015 at an estimated cost of approximately $0.1 billion. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total capacity of 76,000 bpd.

Sunday Creek Terminal Expansion
In January 2014, the Company announced it will construct additional facilities at its existing Sunday Creek Terminal, located in the Christina Lake area of northern Alberta, to support production growth from the Christina Lake oil sands project operated by Cenovus Energy Inc. and jointly owned with ConocoPhillips. The expansion includes development of a new site adjacent to the existing terminal, construction of a new 350,000 barrel tank with associated piping, pumps and measurement equipment, as well as civil construction work for a future tank. The estimated cost for the expansion is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion and a targeted in-service date of the third quarter of 2015.

Canadian Mainline System Terminal Flexibility and Connectivity
As part of the Light Oil Market Access Program initiative, the Company is undertaking the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The modifications are comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections. These projects have varying completion dates from 2013 through 2015. The cost of the project is expected to be approximately $0.7 billion following the completion of a detailed engineering review. The revised estimate reflects enhanced tankage, terminalling and connectivity in conjunction with the Company's Canadian Mainline Expansion project. Refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Canadian Mainline Expansion*. Expenditures to date total approximately $0.2 billion.

Woodland Pipeline Extension
The joint venture Woodland Pipeline Extension Project will extend the Woodland Pipeline south from Enbridge's Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 388-kilometre (241-mile) 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. Enbridge's share of the estimated capital cost of the project is approximately $0.6 billion, with expenditures incurred to date of approximately $0.2 billion. Subject to finalization of scope and a definitive cost estimate, the project has a target in-service date of the third quarter of 2015.

JACOS Hangingstone Project
Enbridge will undertake the construction of facilities and provide transportation services to the Japan Canada Oil Sands Limited (JACOS) Hangingstone Oil Sands Project (JACOS Hangingstone). JACOS and Nexen Energy ULC, a wholly owned subsidiary of China National Offshore Oil Corporation Limited, are partners in the project which is operated by JACOS. Subject to regulatory approval, Enbridge plans to construct a new 53-kilometre (33-mile) 12-inch lateral pipeline to connect the JACOS Hangingstone project site to Enbridge's existing Cheecham Terminal. The project will provide capacity of 40,000 bpd at an estimated cost of approximately $0.1 billion and is expected to enter service in 2016.

Wood Buffalo Extension
In 2013, Enbridge was selected by Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (the Fort Hills Partners), as well as the Suncor Energy Oil Sands Limited Partnership (Suncor Partnership), to develop a new pipeline to transport crude oil production to Enbridge's mainline hub at Hardisty, Alberta. The proposed Wood Buffalo Extension will extend Enbridge's existing Wood Buffalo Pipeline and includes construction of a new 450-kilometre (281-mile) 30-inch pipeline from Enbridge's Cheecham Terminal to its Battle River Terminal at Hardisty, as well as associated terminal upgrades. The completed project will provide capacity of 490,000 bpd of diluted bitumen to be transported for the proposed Fort Hills Partners' oil sands project (Fort Hills Project) in northeastern Alberta and Suncor Partnership's oil sands production in the Athabasca region. Subject to regulatory approvals, the project is expected to be completed in 2017 at an estimated cost of approximately $1.6 billion.

Norlite Pipeline System
Enbridge is undertaking the development of Norlite Pipeline System (Norlite), a new industry diluent pipeline originating from Edmonton to meet the needs of multiple producers in the Athabasca oil sands region. The scope of the project was increased to a 24-inch diameter pipeline, which will provide an initial capacity of approximately 224,000 bpd of diluent, with the potential to be further expanded to approximately 400,000 bpd of capacity with the addition of pump stations. Norlite will be anchored by throughput commitments from both the Fort Hills Partners for production from the proposed Fort Hills Project and from Suncor Partnership's proprietary oil sands production. Norlite will involve the construction of a new 449-kilometre (278-mile) pipeline from Enbridge's Stonefell Terminal to its Cheecham Terminal with an extension to Suncor Partnership's East Tank Farm, which is adjacent to Enbridge's existing Athabasca Terminal. A potential 40-kilometre (25-mile) lateral pipeline to Enbridge's Norealis Terminal is also being considered.

Under an agreement with Keyera Corp. (Keyera), Norlite has the right to access certain existing capacity on Keyera's pipelines between Edmonton and Stonefell and, in exchange, Keyera has elected to participate in the new pipeline infrastructure project as a 30% non-operating owner. Subject to regulatory and other approvals as well as finalization of scope, Norlite is expected to be completed in 2017 at an estimated cost of approximately $1.4 billion.

Canadian Line 3 Replacement Program
In March 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. The Canadian portion of the Line 3 Replacement Program (Canadian L3R Program) will complement existing integrity programs by replacing approximately 1,084-kilometres (673-miles) of the remaining line segments of the existing Line 3 pipeline between Hardisty, Alberta and Gretna, Manitoba. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow the

Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in the second half of 2017. Following the completion of a definitive cost estimate in the second quarter of 2014, the estimated capital cost of the Canadian L3R Program is approximately $4.9 billion, with expenditures to date of approximately $0.1 billion. Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the Competitive Toll Settlement (CTS). For discussion on EEP's portion of the Line 3 Replacement Program refer to *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – United States Line 3 Replacement Program*.

GAS DISTRIBUTION

Greater Toronto Area Project

EGD will undertake the expansion of its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and to continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $0.7 billion, the GTA project will involve the construction of two new segments of pipeline, a 27-kilometre (17-mile) 42-inch diameter pipeline and a 23-kilometre (14-mile) 36-inch diameter pipeline in Toronto, Ontario, as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. With the OEB approval received in January 2014, construction is targeted to start in late 2014 and completion of the project is expected by the end of 2015.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Pipestone and Sexsmith Project

In 2012, the Company acquired from Encana Corporation (Encana) certain sour gas gathering and compression facilities located in the Peace River Arch (PRA) region of northwest Alberta (collectively, Pipestone and Sexsmith). These facilities were either in service (Sexsmith) or under construction (Pipestone) at the time of acquisition. Construction of new gathering lines and NGL handling facilities were completed in June 2014. Enbridge's investment in Pipestone and Sexsmith is approximately $0.3 billion. Enbridge also retains an exclusive right to work with Encana on facility scoping for development of additional major midstream facilities in the liquids-rich PRA region.

Blackspring Ridge Wind Project

In 2013, Enbridge secured a 50% interest in the development of the 300-megawatt (MW) Blackspring Ridge Wind Project (Blackspring Ridge), located 50 kilometres (31 miles) north of Lethbridge, Alberta in Vulcan County. The project was constructed under a fixed price engineering, procurement and construction contract and commercial operations commenced in May 2014. Renewable Energy Credits generated from Blackspring Ridge are contracted to Pacific Gas and Electric Company under a 20-year purchase agreement. The electricity is being sold into the Alberta power pool with pricing fixed on 75% of production through long-term price swap arrangements. The Company's total investment in the project is approximately $0.3 billion.

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge is constructing and will own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the Jack St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 100 million cubic feet per day (mmcf/d). The Jack St. Malo portion of the WRGGS is expected to be placed into service in the fourth quarter of 2014 and the Big Foot Oil Pipeline (Big Foot Pipeline) portion is expected to be placed into service in mid-2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

Big Foot Oil Pipeline
Under agreements with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc., Enbridge is constructing a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge's undertaking of the WRGGS construction, discussed above. Upon completion of the project, Enbridge will operate the Big Foot Pipeline, located approximately 274 kilometres (170 miles) south of the coast of Louisiana. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion. The Big Foot Pipeline is expected to enter service mid-2015.

Keechi Wind Project
In January 2014, Enbridge announced it had entered into an agreement with Renewable Energy Systems Americas Inc. (RES Americas) to own and operate the 110-MW Keechi Wind Project (Keechi), located in Jack County, Texas, at an investment of approximately US$0.2 billion, with expenditures incurred to date of approximately US$0.1 billion. RES Americas is constructing the wind project under a fixed price, engineering, procurement and construction agreement, with expected completion in the first quarter of 2015. Keechi will deliver 100% of the electricity generated into the Electric Reliability Council of Texas, Inc. market under a 20-year power purchase agreement with Microsoft Corporation.

Heidelberg Lateral Pipeline
The Company will construct, own and operate a crude oil pipeline in the Gulf of Mexico to connect the proposed Heidelberg development, operated by Anadarko Petroleum Corporation, to an existing third-party system. The Heidelberg Lateral Pipeline (Heidelberg), a 58-kilometre (36-mile), 20-inch diameter pipeline with capacity of 100,000 bpd, will originate in Green Canyon Block 860, approximately 320 kilometres (200 miles) southwest of New Orleans, Louisiana, and in an estimated 1,600 metres (5,300 feet) of water. Heidelberg is expected to be operational by 2016 at an approximate cost of US$0.1 billion.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.
Line 6B 75-Mile Replacement Program
The Line 6B 75-Mile Replacement Program included the replacement of 120 kilometres (75 miles) of non-contiguous sections of Line 6B of EEP's Lakehead System. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments were completed in components, with approximately 104 kilometres (65 miles) of segments placed in service in 2013. The two remaining 8-kilometre (5-mile) segments in Indiana were placed in service in March 2014. The total cost of the replacement program was approximately US$0.4 billion and EEP is recovering these costs through a tariff surcharge that is part of the system-wide rates for the Lakehead System.

Eastern Access
The Eastern Access initiative includes a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. Projects being undertaken by EEP include an expansion of its Line 5 and expansions of the United States mainline involving the Spearhead North Pipeline (Line 62) and further segments of Line 6B. For discussion on Enbridge's portion of Eastern Access refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Eastern Access*.

In 2013, EEP completed and placed into service the expansion of its Line 5 light crude oil line between Superior, Wisconsin and the international border at the St. Clair River. The Line 5 expansion increased capacity by 50,000 bpd at an approximate cost of US$0.1 billion. Also in 2013, EEP completed and placed into service the expansion of Line 62 between Flanagan, Illinois and Griffith, Indiana, which increased capacity by 105,000 bpd.

EEP is also replacing additional sections of Line 6B in Indiana and Michigan, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, as well as tanks at Flanagan, Stockbridge and Hartsdale, to increase capacity from 240,000 bpd to 500,000 bpd. Portions of the existing 30-inch diameter pipeline are being replaced with 36-inch diameter pipe. The Line 6B project is split into two phases. The segment between Griffith and Stockbridge was completed in May 2014 and the segment from Ortonville, Michigan to the international border at the St. Clair River is now expected to be completed in the fourth quarter of 2014. The replacement of the Line 6B sections is in addition to the Line 6B 75-mile Replacement Program discussed previously. Following detailed engineering estimates completed in the first quarter of 2014 which reflect issues with local ground terrain conditions including tie-ins, the expected cost of the United States mainline expansions is approximately US$2.4 billion, and includes the US$0.1 billion cost of the previously discussed Line 5 expansion.

The Eastern Access initiative also includes a further upsizing of EEP's Line 6B. The Line 6B capacity expansion from Griffith, Indiana to Stockbridge, Michigan will increase capacity from 500,000 bpd to 570,000 bpd and will include pump station modifications at Griffith, Niles and Mendon stations, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. Following the completion, in the first quarter of 2014, of a detailed engineering estimate and a scope revision that removed a proposed tank, the total cost of the projects is approximately US$0.3 billion. The projects are expected to be placed into service in 2016.

The total estimated cost of the projects being undertaken by EEP as part of the Eastern Access initiative including the United States mainline expansions, the Line 5 expansion and the Line 6B capacity expansion project, is approximately US$2.7 billion, with expenditures to date of approximately US$1.8 billion. The Eastern Access projects undertaken by EEP are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

Lakehead System Mainline Expansion

The Lakehead System Mainline Expansion includes several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States border, near Neche, North Dakota, to Flanagan, Illinois. These projects are in addition to expansions of the Lakehead System mainline being undertaken as part of the Eastern Access initiative and includes the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61).

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase will increase capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. The second phase of the expansion will increase capacity from 570,000 bpd to 800,000 bpd, at an estimated capital cost of approximately US$0.2 billion. Both phases of the Alberta Clipper expansion require only the addition of pumping horsepower and no pipeline construction. Subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd, the initial phase is expected to be substantially complete in September 2014 and the second phase is expected to be in-service in 2015. It is now anticipated that obtaining regulatory approval will take longer than originally planned though approval is expected in mid-2015. A number of temporary system optimization actions are being undertaken to substantially mitigate any impact on throughput associated with the initial 120,000 bpd capacity increase.

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. The initial phase includes an increase in capacity from 400,000 bpd to 560,000 bpd at an estimated capital cost of approximately US$0.2 billion. EEP also plans to undertake a further expansion of the Southern Access line between Superior and Flanagan to increase capacity from 560,000 bpd to 1,200,000 bpd. Following completion of a more detailed engineering estimate in the first quarter of 2014, the second phase of the Southern Access expansion is expected to cost approximately US$1.2 billion. Both phases of the expansion would require only the addition of pumping horsepower and crude oil tanks at existing sites, with no pipeline construction. The target in-service date for the first phase of the expansion is the third quarter 2014. For the second phase of the expansion, which remains subject to regulatory and other approvals, the pump station expansion is expected to be available for service in 2015, with additional tankage requirements expected to be completed in 2016.

As part of the Light Oil Market Access Program, EEP also plans to expand the capacity of the Lakehead System between Flanagan, Illinois and Griffith, Indiana. This section of the Lakehead System will be expanded by constructing a 127-kilometre (79-mile), 36-inch diameter twin of the existing Spearhead North Pipeline (Line 62). The project is expected to be completed at an estimated cost of approximately US$0.5 billion. Subject to regulatory and other approvals, the new line will have an initial capacity of 570,000 bpd and is expected to be placed into service in late 2015.

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.3 billion, with expenditures incurred to date of approximately US$0.5 billion. EEP will operate the project on a cost-of-service basis. The Lakehead System Mainline Expansion is funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

Beckville Cryogenic Processing Facility
EEP and its partially owned subsidiary MEP are constructing a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas. The Beckville Plant will offer incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where the East Texas system is located. The Beckville Plant has a planned natural gas processing capability of 150 mmcf/d and is also expected to produce 8,500 bpd of NGL. The Beckville Plant is expected to be placed into service in the first quarter of 2015 at an estimated cost of approximately US$0.1 billion.

Sandpiper Project
As part of the Light Oil Market Access Program initiative, EEP plans to undertake the Sandpiper project (Sandpiper) which will expand and extend EEP's North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota by adding 250,000 bpd of capacity between Tioga and Berthold, North Dakota and 225,000 bpd of capacity between Berthold and Clearbrook, both with new 24-inch diameter pipelines, as well as adding 375,000 bpd of capacity between Clearbrook and Superior with a new 30-inch diameter pipeline. Sandpiper is expected to cost approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.2 billion.

MPC has been secured as an anchor shipper for Sandpiper. As part of the arrangement, EEP, through its subsidiary, North Dakota Pipeline Company LLC (NDPC) (formerly known as Enbridge Pipelines (North Dakota) LLC), and Williston Basin Pipeline LLC (Williston), an affiliate of MPC, entered into an agreement to, among other things, admit Williston as a member of NDPC. Williston will fund 37.5% of Sandpiper construction and will have the option to participate in other growth projects within NDPC, unless specifically excluded by the agreement; this investment is not to exceed US$1.2 billion in aggregate. In return for funding part of Sandpiper's construction, Williston will obtain an approximate 27% equity interest in NDPC at the in-service date of Sandpiper, targeted for early 2016.

A petition was filed with the FERC to approve recovery of Sandpiper's costs through a surcharge to the NDPC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. In March 2013, the FERC denied the petition on procedural grounds. In late 2013, EEP held an open season to solicit commitments from shippers for capacity created by Sandpiper. The open season closed in late January 2014 with the receipt of a further capacity commitment which can be accommodated within the planned incremental capacity identified above. EEP re-filed its petition with the FERC on February 12, 2014 and received a FERC declaratory order in May 2014 approving the tariffs structure for the project. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals.

United States Line 3 Replacement Program
In March 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. EEP will undertake the United States portion of the Line 3 Replacement Program (U.S. L3R Program) which will complement existing integrity programs by replacing approximately 576-kilometres (358-miles) of the remaining line segments of the existing Line 3 pipeline between Neche,

North Dakota and Superior. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd.

Subject to regulatory and other approvals, the U.S. L3R Program is targeted to be completed in the second half of 2017 at an estimated capital cost of approximately US$2.6 billion. The U.S. L3R Program will be jointly funded by Enbridge and EEP at participation levels that are subject to finalization. EEP will recover the costs based on its existing Facilities Surcharge Mechanism with the initial term of the agreement being 15 years. For the purpose of the toll surcharge, the agreement specifies a 30-year recovery of the capital based on a cost of service methodology.

GROWTH PROJECTS – OTHER PROJECTS UNDER DEVELOPMENT

The following projects have been announced by the Company, but have not yet met Enbridge's criteria to be classified as commercially secured. The Company also has significant additional attractive projects under development which have not yet progressed to the point of public announcement. In its long-term funding plans, the Company makes full provision for all commercially secured projects and makes provision for projects under development based on an assessment of the aggregate securement success anticipated. Actual securement success achieved could exceed or fall short of the anticipated level.

LIQUIDS PIPELINES

Northern Gateway Project

Northern Gateway Project (Northern Gateway) involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to transport imported condensate from Kitimat to the Edmonton area and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

On December 19, 2013, the Joint Review Panel (JRP) issued its report on Northern Gateway. The report found that the petroleum industry is a significant driver of the Canadian economy and an important contributor to the Canadian standard of living. The JRP found that the potential economic effects of Northern Gateway on local, regional and national economies would be positive and would likely be significant. The JRP is also of the view that the Company's commitments break new ground by providing an unprecedented level of long-term economic, environmental and social benefits to Aboriginal groups. It noted that the benefits of Northern Gateway outweigh its burdens and that "Canadians would be better off with the Enbridge Northern Gateway Project than without it."

The JRP found that Northern Gateway provided appropriate and effective opportunities for the public and potentially-affected parties to learn about the project and to provide their views and concerns to the Company. The JRP was satisfied that Northern Gateway considered, and was responsive to, the input it received regarding the design, construction and operation of the project.

The JRP found Northern Gateway applied a careful and precautionary approach to its environmental assessment and that Northern Gateway had presented a level of engineering design information that met, or exceeded, regulatory requirements for a thorough and comprehensive review in terms of whether or not it can construct and operate the project in a safe and responsible manner that protects people and the environment. The JRP found that Northern Gateway followed good engineering practice in determining a route that avoids or minimizes exposure to geohazards, had taken all reasonable steps to design a project that would minimize risks of project malfunctions and accidents due to naturally occurring events and that mandatory and voluntary measures outlined by the Company would reduce the potential for human error to the greatest extent possible.

The JRP also referenced the conclusions of the TERMPOL committee and the evidence of various expert witnesses appearing on behalf of Northern Gateway and the Government of Canada in its assessment of the safety of marine transport and concluded that shipping along the north coast of British Columbia could be accomplished safely the vast majority of the time even in the absence of many of the mitigation measures that would be in place for Northern Gateway. These additional mitigation measures would include reduced vessel speeds, escort tugs, redundant navigational systems and avoiding congestion in the narrower parts of the shipping channels. The JRP noted Northern Gateway's commitments represent a substantial increase in spill response capabilities beyond those required by existing legislation and currently existing on the west coast of British Columbia, that they are based on international best practice and continual advances in technology and spill response planning. The JRP included an appendix with 209 conditions that the JRP recommended be included in any certificate that was issued.

The JRP recommended to the Governor in Council that Certificates of Public Convenience and Necessity for the oil and condensate pipelines, incorporating the terms and conditions in their report, be issued to Northern Gateway pursuant to Part III of the NEB Act. The Government of Canada has consulted with Aboriginal groups on the JRP report and its recommendations prior to making its decision on whether to direct the NEB to issue the certificates for the pipelines. Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so.

On June 17, 2014, the Northern Gateway received Governor in Council approval, subject to the 209 conditions recommended by the JRP. The NEB issued the Certificates of Public Convenience and Necessity on June 18, 2014.

The cost estimate included in the Northern Gateway filing with the JRP reflects a preliminary estimate prepared in 2004 and escalated to 2010. A detailed estimate based on full engineering analysis of the pipeline route and terminal location is currently being prepared. The detailed estimate will reflect a larger proportion of high cost terrain, longer tunnelling requirements and more extensive terminal site rock excavation than provided for in the preliminary estimate, which is expected to result in a significant increase in the cost estimate.

Five applications for judicial review were filed with the Federal Court and the Federal Court of Appeal; three from Aboriginal groups and two from environmental groups following the release of the JRP report in December. Those applications have now been withdrawn and the same parties along with a number of additional Aboriginal groups and UNIFOR have filed applications to challenge the Governor in Council decision and the subsequent issuance of the Certificates. On July 3, 2014, the Federal Court of Appeal issued a Procedural Direction for Applications for Leave to Appeal the decision of the NEB.

Subject to continued commercial support, regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service in 2018 at the earliest. The timing and outcome of judicial reviews could also impact the start of construction or other project activities, which may lead to a delay in the start of operations beyond the current forecast.

Expenditures to date, which relate primarily to the regulatory process, are approximately $0.5 billion, of which approximately half is being funded by potential shippers on Northern Gateway. Given the many uncertainties surrounding Northern Gateway, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

The JRP posts public filings related to Northern Gateway on its website at http://gatewaypanel.review-examen.gc.ca/clf-nsi/hm-eng.html and Northern Gateway also maintains a website at www.northerngateway.ca where the full regulatory application submitted to the NEB, the 2010 Enbridge Northern Gateway Community Social Responsibility Report and the December 19, 2013 Report of the JRP on the Northern Gateway Application are available. ***None of the information contained on, or connected to, the JRP website or the Northern Gateway website is incorporated in or otherwise part of this MD&A.***

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

NEXUS Gas Transmission Project

In 2012, Enbridge, DTE Energy Company (DTE) and Spectra Energy Corp. (Spectra) announced the execution of a Memorandum of Understanding (MOU) to jointly develop the NEXUS Gas Transmission System, a project that would move growing supplies of Ohio Utica shale gas to markets in the United States midwest, including Ohio and Michigan, and Ontario, Canada. The MOU has expired and Enbridge is in discussions with Spectra and DTE regarding the terms of its continued participation in the project.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Canadian Mainline	**131**	86	**272**	229
Regional Oil Sands System	**48**	36	**90**	77
Southern Lights Pipeline	**12**	9	**24**	21
Seaway Pipeline	**13**	16	**23**	29
Spearhead Pipeline	**9**	8	**18**	17
Feeder Pipelines and Other	**7**	4	**11**	5
Adjusted earnings	**220**	159	**438**	378
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**211**	(186)	**39**	(258)
Canadian Mainline - Line 9B costs incurred during reversal	**(4)**	-	**(4)**	-
Regional Oil Sands System - make-up rights adjustment	**2**	-	**-**	-
Regional Oil Sands System - leak insurance recoveries	**4**	-	**4**	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**-**	(40)	**-**	(40)
Spearhead Pipeline - make-up rights adjustment	**(1)**	-	**(1)**	-
Feeder Pipelines and Other - make-up rights adjustment	**2**	-	**2**	-
Feeder Pipelines and Other - project development costs	**(3)**	-	**(3)**	-
Earnings/(loss) attributable to common shareholders	**431**	(67)	**475**	80

Canadian Mainline

Canadian Mainline adjusted earnings for the three and six months ended June 30, 2014 increased compared with the second quarter and the first half of 2013. Higher adjusted earnings were primarily driven by higher throughput supported by several factors: increased oil sands production; volumes diverted from competing systems; strong refinery demand in the midwest market partly due to a start-up of a midwest refinery's conversion to heavy oil processing in the second quarter of 2014; and successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Higher terminalling revenues as well as lower operating and administrative costs were also positive factors relative to the comparative periods.

On a year-to-date basis, partially offsetting these positive impacts was a lower Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll in the first quarter of 2014 compared with the equivalent 2013 period. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher in the first quarter of 2014 due to the recovery of incremental costs associated with EEP's growth projects. Tolls were not a significant driver of the second quarter variance as the Canadian Mainline IJT Residual Benchmark Toll was US$1.81 per barrel for both the second quarter of 2014 and 2013. Higher power costs associated with incremental throughput as well as higher depreciation from an increased asset base also impacted adjusted earnings for the first half of 2014. Finally, Canadian Mainline adjusted earnings for the first half of 2014 continued to be impacted by the absence of revenues from Line 9B, which was idled in late 2013 and is being reversed and expanded as part of the Company's Eastern Access initiative. Line 9B is expected to resume service in the fourth quarter of 2014. For further information on Line 9B refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Eastern Access.*

EEP delayed its annual April 1 tariff filing for its Lakehead System as it was in negotiations with the Canadian Association of Petroleum Producers (CAPP) concerning certain components of the tariff rate structure. The toll application was filed with the FERC on June 27, 2014, and effective August 1, 2014, the Lakehead System Toll will increase to US$2.49 per barrel. The IJT Benchmark Toll, which is adjusted annually on July 1, increased from US$3.98 per barrel to US$4.02 per barrel effective July 1, 2014. The Canadian Mainline IJT Residual Benchmark Toll, which represents the difference between the IJT Benchmark Toll and the Lakehead System Local Toll, will increase to US$1.85 per barrel effective July 1, 2014 and will subsequently decrease to US$1.53 per barrel effective August 1, 2014 when the revised Lakehead System Toll becomes effective.

Supplemental information on Canadian Mainline adjusted earnings for the three and six months ended June 30, 2014 and 2013 is provided below:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Revenues	**382**	324	**755**	711
Expenses				
Operating and administrative	**99**	114	**183**	213
Power	**38**	26	**76**	55
Depreciation and amortization	**65**	60	**131**	118
	202	200	**390**	386
	180	124	**365**	325
Other income/(expense)	**(3)**	4	**(2)**	4
Interest expense	**(39)**	(40)	**(78)**	(80)
	138	88	**285**	249
Income taxes	**(7)**	(2)	**(13)**	(20)
Adjusted earnings	**131**	86	**272**	229
Effective United States to Canadian dollar exchange rate[1]	**1.021**	0.997	**1.020**	0.998

As at June 30,	**2014**	2013
(United States dollars per barrel)		
IJT Benchmark Toll[2]	**$3.98**	$3.94
Lakehead System Local Toll[3]	**$2.17**	$2.13
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.81**	$1.81

1 *Inclusive of realized gains and losses on foreign exchange derivative financial instruments.*

2 *The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2013, the IJT Benchmark Toll increased from US$3.94 to US$3.98.*

3 *The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective July 1, 2013, this toll increased from US$2.13 to US$2.18. Effective January 1, 2014, this toll decreased to US$2.17.*

4 *The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. For any shipment, this toll is the difference between the IJT Benchmark Toll for that shipment and the Lakehead System Local Toll for that shipment. This toll decreased from US$1.81 to US$1.80 effective July 1, 2013. Effective January 1, 2014, this toll increased to US$1.81.*

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
Throughput[1] *(thousand barrels per day (kbpd))*	**1,968**	1,604	**1,936**	1,693

1 *Throughput volume, presented in kbpd, represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.*

Regional Oil Sands System
Regional Oil Sands System adjusted earnings increased for the three and six months ended June 30, 2014 compared with the corresponding 2013 periods. Adjusted earnings growth was primarily driven by contributions from the Norealis Pipeline which was completed in April 2014, as well as higher throughput on the Athabasca mainline. Partially offsetting the increase in adjusted earnings were higher depreciation expense from a larger asset base and higher operating and administrative, interest and tax expenses from increased operational activities.

Southern Lights Pipeline
Southern Lights Pipeline earnings for the three and six months ended June 30, 2014 increased compared with the comparative 2013 periods and reflected higher recoveries of depreciation expense under the cost of service model.

Seaway Pipeline
Seaway Pipeline earnings for the first half of 2014 decreased compared with the comparative 2013 period. Higher financing and administrative costs as well as higher power costs were partially offset by higher throughput and a more favourable crude mix transported on Seaway Pipeline.

Feeder Pipelines and Other
Feeder Pipelines and Other adjusted earnings for the six month period ended June 30, 2014 were higher compared with the same period of 2013 due to lower business development costs not eligible for capitalization during the first quarter of 2014.

Liquids Pipelines earnings/(loss) were impacted by the following adjusting items:

- Canadian Mainline earnings/(loss) for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Canadian Mainline earnings for 2014 included depreciation and interest expense charged to Line 9B while it was idled and undergoing a reversal as part of the Company's Eastern Access initiative.
- Regional Oil Sands System earnings for the second quarter of 2014 included a make-up rights adjustment.
- Regional Oil Sands System earnings for 2014 included insurance recoveries associated with the Line 37 crude oil release which occurred in June 2013.
- Regional Oil Sands System earnings for 2013 included a charge related to the Line 37 crude oil release which occurred in June 2013.
- Spearhead Pipeline earnings for 2014 included a make-up rights adjustment.
- Feeder Pipelines and Other earnings for 2014 included a make-up rights adjustment.
- Feeder Pipelines and Other earnings for 2014 included certain business development costs related to Northern Gateway that are expected to be recovered over the life of the project.

GAS DISTRIBUTION

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**12**	23	**103**	123
Other Gas Distribution and Storage	**3**	2	**15**	15
Adjusted earnings	**15**	25	**118**	138
EGD - (warmer)/colder than normal weather	**4**	2	**37**	(4)
Earnings attributable to common shareholders	**19**	27	**155**	134

EGD operated the first half of 2014 under OEB approved interim distribution rates pending a final decision by the OEB on EGD's application for a five-year customized IR rate-setting mechanism with an effective date of January 1, 2014. On July 17, 2014, the OEB approved EGD's customized IR rate-setting mechanism, with modifications. The difference in revenues under the interim rates and final approved

2014 rates will be adjusted as part of the October 2014 Quarterly Rate Adjustment Mechanism. See *Recent Developments – Gas Distribution – Enbridge Gas Distribution – Incentive Regulation*.

EGD adjusted earnings decreased for the three and six months ended June 30, 2014 compared with the same periods in 2013. The decrease between comparative periods is largely attributed to a gas transportation cost adjustment related to the first half of 2013 which was recorded in the third quarter of 2013. Excluding the impact of the gas transportation adjustment, EGD adjusted earnings for both the three and six months ended June 30, 2014 were moderately lower compared with the corresponding 2013 periods. The lower adjusted earnings reflected higher depreciation expense due to the growth in asset base and higher interest expense, partially offset by increased earnings from customer growth.

Adjusted earnings from Other Gas Distribution and Storage for the first half of 2014 included a loss from EGNB related to a contract to sell natural gas to the province of New Brunswick. Due to an abnormally cold winter in the first quarter of 2014, costs associated with the fulfilment of the contract were higher than the revenues received. This contract expires in the fourth quarter of 2014 and is not expected to have a significant impact to adjusted earnings for the remainder of the year.

Gas Distribution earnings were impacted by the following adjusting item:
- EGD earnings were adjusted to reflect the impact of weather.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Aux Sable	**4**	8	**11**	16
Energy Services	**6**	42	**30**	75
Alliance Pipeline US	**12**	11	**24**	21
Vector Pipeline	**3**	6	**9**	13
Enbridge Offshore Pipelines (Offshore)	**(4)**	(2)	**-**	-
Other	**6**	8	**12**	7
Adjusted earnings	**27**	73	**86**	132
Energy Services - changes in unrealized derivative fair value gains	**81**	143	**217**	113
Offshore - gain on sale of non-core assets	**-**	-	**43**	-
Other - changes in unrealized derivative fair value loss	**(1)**	(56)	**(2)**	(56)
Earnings attributable to common shareholders	**107**	160	**344**	189

Aux Sable earnings decreased for the three and six months ended June 30, 2014 compared with the 2013 comparative periods and reflected lower volumes processed at the Palermo Conditioning Plant and higher administrative expense.

Energy Services operates a physical commodity marketing business which captures value from quality, time and location differentials when opportunities arise. To execute these strategies Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines. Adjusted earnings decreased in the second quarter of 2014 compared with the exceptionally strong second quarter of 2013 reflecting narrowing location spreads and less favourable conditions in certain markets accessed by committed transportation capacity, with associated unrecovered demand charges.

Similarly, Energy Services adjusted earnings for the first half of 2014 were lower compared with the exceptionally strong first half of 2013. In addition to the factors noted above, losses were realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. During the second quarter of 2014, the Company closed out a forward component of such derivative contracts which had been determined to be no longer effective. Partially offsetting the decrease in the adjusted earnings for the first half of 2014 were favourable natural gas location differentials caused by abnormal winter weather conditions during the first quarter of 2014. Adjusted earnings from Energy Services are dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Alliance Pipeline US earnings increased in both the three and six months ended June 30, 2014 compared with the equivalent 2013 periods due to an increase in depreciation expense recovered in tolls as well as earnings from the Tioga Lateral which was placed into service in September 2013.

Vector Pipeline earnings in the three and six months ended June 30, 2014 decreased compared with the comparative periods of 2013 and reflected lower depreciation expense recognized in tolls. For the six months ended June 30, 2014, the decrease in earnings was partially offset by higher uncommitted transportation volumes coupled with higher prices. Higher volumes were primarily driven by increased demand for natural gas in eastern North America in response to abnormal winter weather conditions experienced in the first quarter of 2014.

Offshore adjusted loss in the second quarter of 2014 reflected the absence of earnings from the disposal of non-core assets which was finalized in March 2014, partially offset by cost savings achieved from the Company's decision not to renew windstorm insurance coverage effective May 2013. Additionally, persistent weak volumes within Offshore's corridor due to decreased production in the Gulf of Mexico have resulted in challenging market conditions. As such, Offshore adjusted earnings are expected to remain weak, until such time as the WRGGS and Big Foot Pipeline are placed into service, which are expected to occur in the fourth quarter of 2014 and mid-2015, respectively.

The increase in adjusted earnings from Other in the first half of 2014 compared with the first half of 2013 was primarily attributable to an increase in the fees earned from the Company's investment in the Cabin Gas Plant and the positive impact of new wind farms placed into service over the past two years. Partially offsetting the increase in adjusted earnings were higher depreciation expense and financing costs from the Montana-Alberta Tie-Line and higher business development costs not eligible for capitalization. Adjusted earnings for the second quarter of 2014 decreased compared with the comparative 2013 period primarily as a result of the transformer outage related costs at the Massif du Sud wind farm which more than offset the positive 2014 first half trends, noted above.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following adjusting items:

- Energy Services earnings for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory.
- Energy Services adjusted earnings for 2014 excluded a realized loss of $71 million incurred during the second quarter of 2014 to close out certain forward derivative financial contracts intended to hedge the value of committed physical transportation capacity in certain markets accessed by Energy Services, but determined to be no longer effective in doing so.
- Adjusted earnings for the first half of 2013 excluded a realized loss of $58 million incurred to close out certain forward derivative contracts intended to hedge forecasted Energy Services transactions which did not occur.
- Offshore earnings for 2014 included a gain from the disposal of non-core assets.
- Other earnings for each period reflected changes in unrealized fair value losses on the long-term power price derivative contracts acquired to hedge expected revenues and cash flows from Blackspring Ridge.

SPONSORED INVESTMENTS

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Enbridge Energy Partners, L.P. (EEP)	**50**	37	**95**	73
Enbridge Energy, Limited Partnership (EELP)	**13**	8	**20**	16
Enbridge Income Fund (the Fund)	**33**	26	**65**	49
Adjusted earnings	**96**	71	**180**	138
EEP - changes in unrealized derivative fair value gains/(loss)	**(3)**	4	**(3)**	3
EEP - make-up rights adjustment	**(1)**	-	**(1)**	-
EEP - leak remediation costs	**(5)**	(6)	**(5)**	(30)
EEP - leak insurance recoveries	**-**	6	**-**	6
EEP - tax rate differences/changes	**-**	(3)	**-**	(3)
Earnings attributable to common shareholders	**87**	72	**171**	114

EEP adjusted earnings increased for the three and six months ended June 30, 2014 compared with the corresponding 2013 periods. Adjusted earnings increased in EEP's liquids business primarily as a result of higher throughput and tolls on EEP's major liquids pipelines, as well as contributions from assets recently placed into service. New assets contributing to the increase included the Bakken Expansion and Access programs, which enhanced crude oil gathering capabilities on the North Dakota system, and the recently completed Lakehead System Line 6B 75-mile replacement program. Partially offsetting the increase in adjusted earnings in EEP's liquids business were higher operating and administrative costs, incremental power costs associated with higher throughput and higher depreciation expense from an increased asset base. EEP's liquids business was also negatively impacted by the renegotiation of a tolling methodology on EEP's Line 14 which occurred in the second quarter of 2014. Within EEP's natural gas and NGL businesses, which it holds directly and indirectly through its partially owned subsidiary, MEP, lower volumes had a negative impact on adjusted earnings. Finally, EEP adjusted earnings for the first half of 2014 continued to reflect higher earnings from Enbridge's May 2013 investment in preferred units of EEP.

EEP delayed its annual April 1 tariff filing for its Lakehead System as it was in negotiations with the CAPP concerning certain components of the tariff rate structure. The toll application was filed with the FERC on June 27, 2014, and effective August 1, 2014, the Lakehead System Toll will increase to US$2.49 per barrel, with the current Lakehead Toll remaining at US$2.17 per barrel until that time.

Enbridge Energy, Limited Partnership (EELP) earnings reflect its interest in Alberta Clipper, as well as interests in both the Eastern Access and Lakehead System Mainline expansion projects. Earnings from EELP increased for the three and six months ended June 30, 2014 compared with the corresponding 2013 periods and reflected increased contributions from assets recently placed into service, including the Line 5 expansion completed in May 2013 and the first phase of the Line 6B expansion project which was placed into service in May 2014.

Earnings for the Fund for the three and six months ended June 30, 2014 were higher compared with the same periods of 2013. Higher earnings reflected strong performance across the Fund's diverse businesses. Among the positive contributors were stronger wind and solar resources on the majority of the Fund's renewable energy assets, although the performance was tempered in the second quarter of 2014 due to lower wind resources. The Fund's liquids business also provided higher contributions primarily from higher earnings from the Saskatchewan System in the second quarter of 2014 and higher earnings from the Bakken Expansion Pipeline in the first quarter of 2014. Also contributing to period-over-period growth in earnings was the absence of an after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance which occurred in the first quarter of 2013.

Sponsored Investments earnings were impacted by the following adjusting items:

- Earnings from EEP for each period included changes in unrealized fair value gains and losses on derivative financial instruments.
- Earnings from EEP for 2014 included a make-up rights adjustment.
- Earnings from EEP for 2014 and 2013 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.*
- Earnings from EEP for 2013 included insurance recoveries associated with the Line 6B crude oil release. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Line 6B Crude Oil Release.*
- Earnings from EEP for 2013 included an out-of-period, non-cash deferred income tax adjustment related to a tax law change.

CORPORATE

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Noverco	**(4)**	(3)	**25**	36
Other Corporate	**(26)**	(19)	**(27)**	(28)
Adjusted earnings/(loss)	**(30)**	(22)	**(2)**	8
Noverco - changes in unrealized derivative fair value loss	**(1)**	(2)	**(5)**	(1)
Other Corporate - changes in unrealized derivative fair value gains/(loss)	**143**	(149)	**(6)**	(254)
Other Corporate - gain on sale of investment	**-**	-	**14**	-
Other Corporate - foreign tax recovery	**-**	-	**-**	4
Other Corporate - impact of tax rate changes	**-**	23	**-**	18
Earnings/(loss) attributable to common shareholders	**112**	(150)	**1**	(225)

Noverco adjusted earnings decreased for both the three and six months ended June 30, 2014 compared with the corresponding 2013 periods. Noverco adjusted earnings included returns on the Company's preferred share investment as well as its equity earnings from Noverco's underlying gas and power distribution investments. Excluding the impact of a small one-time gain on sale of an investment in the first quarter of 2013 and an equity earnings true-up adjustment captured in the first quarter of 2013, Noverco adjusted earnings were comparable between periods. The negative contribution for both the second quarter of 2014 and 2013 reflected seasonality of the quarterly profile of Noverco's underlying gas and power distribution businesses where the majority of its annual earnings are earned during the colder months of the year.

Other Corporate adjusted loss increased in the second quarter of 2014 compared with the second quarter of 2013 and reflected higher preference share dividends due to an increase in the number of preference shares outstanding and higher income taxes, partially offset by lower net Corporate segment finance costs.

Corporate earnings/(loss) were impacted by the following adjusting items:

- Noverco earnings/(loss) for each period included changes in unrealized fair value losses on derivative financial instruments.
- Other Corporate loss for each period included changes in the unrealized fair value gains and losses on derivative financial instruments primarily related to forward foreign exchange risk management positions.
- Other Corporate loss for 2014 included a gain on sale of an investment.
- Other Corporate loss for 2013 was reduced by recovery of taxes related to a historical foreign investment.
- Other Corporate loss for 2013 was impacted by tax rate differences.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge's growth strategy, particularly in light of the record level of growth projects secured or under development. The Company actively manages financial plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. In the near term, the Company generally expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends.

The Company's longer-term financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles, with the objective of diversifying funding sources and maintaining access to low cost capital. In 2014, the Company took a significant action to re-establish EEP as a cost-effective sponsored vehicle by restructuring EEP's equity. The Equity Restructuring is expected to benefit Enbridge in the longer-term by improving EEP's cost of capital and growth outlook, thus increasing the incentive distributions to Enbridge over time. See *Recent Developments – Sponsored Investments – Enbridge Energy Partners, L.P. – Enbridge Energy Partners, L.P. Equity Restructuring*.

In accordance with its funding plan, the Company has completed the following issuances to date in 2014:

- Corporate - $460 million common shares; $1,125 million preference shares; $1,530 million medium-term notes; $1,641 million senior notes; and
- EGD - $300 million medium-term notes.

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge also bolstered its committed bank credit facilities in 2014. The following table provides details of the Company's committed credit facilities at June 30, 2014 and December 31, 2013.

		June 30, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[2]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	**300**	**196**	**104**	300
Gas Distribution	2016-2019	**1,008**	**708**	**300**	713
Sponsored Investments	2015-2018	**4,797**	**1,831**	**2,966**	4,781
Corporate	2015-2018	**11,947**	**3,986**	**7,961**	11,805
		18,052	**6,721**	**11,331**	17,599
Southern Lights project financing[1]	2014-2015	**1,574**	**1,502**	**72**	1,570
Total committed credit facilities		**19,626**	**8,223**	**11,403**	19,169

1 *Total facilities inclusive of $63 million for debt service reserve letters of credit.*
2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

In addition to the committed credit facilities noted above, the Company also has $269 million of uncommitted demand credit facilities, of which $250 million was unutilized as at June 30, 2014.

Subsequent to June 30, 2014, the Company has extended the maturity of a number of credit facilities for another year and increased committed credit facilities by $75 million.

Excluding project financing, the Company's net available liquidity of $12,126 million at June 30, 2014 was inclusive of $795 million of unrestricted cash and cash equivalents and net of bank indebtedness of $453 million.

There are no material restrictions on the Company's cash with the exception of restricted cash of $7 million related to Southern Lights project financing and cash in trust of $6 million for specific shipper commitments. Cash and cash equivalents held by EEP and the Fund are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and monthly for the Fund. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

OPERATING ACTIVITIES

Cash provided by operating activities for the three and six months ended June 30, 2014 was $812 million and $1,145 million, respectively, compared with $937 million and $1,730 million for the three and six months ended June 30, 2013. The comparability of period-over-period cash flows from operating activities is impacted by changes in operating assets and liabilities each period and a dividend of $248 million received in the second quarter of 2013 on the Company's investment in Noverco. Excluding the effect of these items, cash generated from operating activities for the three and six month periods ended June 30, 2014 was higher compared with the comparative periods in 2013 and was primarily due to cash growth delivered by operations. As discussed in Financial Results, the Company experienced higher earnings mainly from higher throughput and new assets in Liquids Pipelines and stronger contributions from EEP and the Fund. Higher distributions from the Company's equity investments during the first half of 2014 also contributed to the period-over-period cash flow growth. Partially offsetting these increases were less favourable arbitrage opportunities in Energy Services.

The Company's operating assets and liabilities had a negative variance of $564 million for the six months ended June 30, 2014, as compared with the corresponding period in 2013. This negative variance was mainly attributable to variations in commodity prices and volumes purchased within Energy Services as well as higher natural gas prices within EGD due to a colder than normal weather during the first three months of 2014.

At June 30, 2014, the Company had a negative working capital position. Despite this negative working capital, the Company continues to have significant liquidity available through committed credit facilities, which allow the funding of liabilities as they become due. As at June 30, 2014, the Company's net available liquidity totalled $12,126 million (December 31, 2013 - $12,909 million). In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

INVESTING ACTIVITIES

Cash used in investing activities for the three and six months ended June 30, 2014 was $2,886 million and $5,629 million, respectively, compared with $1,949 million and $3,592 million for the three and six months ended June 30, 2013. Cash used in investing activities has increased on a period-over-period basis primarily due to additions to property, plant and equipment associated with the Company's growth projects which are further described in *Growth Projects – Commercially Secured Projects*. Additional funding of various investments and joint ventures, primarily the Seaway Pipeline Twinning/Extension project, also contributed to the increased cash usage in 2014.

FINANCING ACTIVITIES

For the three and six months ended June 30, 2014, cash generated from financing activities was $2,490 million and $4,955 million, respectively, compared with $731 million and $1,151 million for the three and six months ended June 30, 2013. The Company continues to execute its funding and liquidity strategy in support of its long-term growth plan. During the first half of 2014, the Company increased its overall debt by $4,490 million compared with a decrease of $140 million in the first half of 2013. The most significant contributor of this increase during the first half of 2014 was the issuance of $3,456 million (2013 - nil) in medium-term and senior notes. The Company also issued preference and common shares during the first half of 2014 for net proceeds of $758 million and $406 million, respectively, compared with $986 million and $614 million for the comparative periods in 2013. Furthermore, the Company bolstered its liquidity during the first half of 2014 through the securement of additional credit facilities.

Additional preference and common shares outstanding gave rise to an increase in the dividends paid during the first six months of 2014 compared with the same period of 2013, partially offsetting the cash inflows from financing activities. Also partially offsetting the cash flows from financing activities were the transactions between the Company's sponsored vehicles and their public unitholders. During the first half of 2014, EEP, MEP and the Fund made distributions, net of contributions, of $216 million to their public unitholders. In the first half of 2013, sponsored vehicles received contributions, net of distributions, of $16 million primarily as a result of their equity issuances to the public.

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended June 30, 2014, dividends declared were $293 million (2013 - $259 million), of which $187 million (2013 - $173 million) were paid in cash and reflected in financing activities. The remaining $106 million (2013 - $86 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the six months ended June 30, 2014, dividends declared were $584 million (2013 - $513 million), of which $372 million (2013 - $337 million) were paid in cash and reflected in financing activities. The remaining $212 million (2013 - $176 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and six months ended June 30, 2014, 36.2% (2013 - 33.2%) and 36.3% (2013 - 34.3%) of total dividends declared were reinvested.

On July 29, 2014, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2014 to shareholders of record on August 15, 2014.

Common Shares	$0.35000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11[1]	$0.30740

1 *This first dividend declared for the Preference Shares, Series 11 includes accrued dividends from May 22, 2014, the date the shares were issued. The regular quarterly dividend of $0.275 per share will take effect on December 1, 2014. See* Recent Developments – Corporate – Preference Share Issuance*.*

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $3,273 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. 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, certain revenues denominated in United States dollars and certain expenses denominated in Euros. The Company has implemented a policy whereby, at a minimum, it economically hedges a level of foreign currency denominated earnings exposures identified over a five-year forecast horizon. The Company may also hedge anticipated foreign currency denominated purchases or sales and 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. The Company has designated a portion of its United States dollar denominated long-term debt and certain derivative foreign exchange contracts as hedges of net investments in United States dollar denominated investments and subsidiaries.

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 2019 through execution of floating to fixed interest rate swaps with an average swap rate of 2.1%.

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 2017. A total of $8,870 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.6%.

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

Commodity Price Risk

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

Equity Price Risk

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

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

The following table presents the effect of derivative instruments on the Company's consolidated earnings and consolidated comprehensive income.

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(60)**	33	**(31)**	47
Interest rate contracts	**(279)**	710	**(521)**	789
Commodity contracts	**(10)**	17	**(17)**	17
Other contracts	**3**	(3)	**8**	(1)
Net investment hedges				
Foreign exchange contracts	**45**	(45)	**(3)**	(67)
	(301)	712	**(564)**	785
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Foreign exchange contracts[1]	**16**	(3)	**15**	(3)
Interest rate contracts[2]	**23**	33	**44**	46
Commodity contracts[3]	**5**	(4)	**12**	(4)
Other contracts[4]	**(3)**	-	**(7)**	-
	41	26	**64**	39
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**3**	(15)	**28**	23
Commodity contracts[3]	**2**	(1)	**3**	(2)
	5	(16)	**31**	21
Amount of gains/(loss) from non-qualifying derivatives included in earnings				
Foreign exchange contracts[1]	**478**	(508)	**58**	(701)
Interest rate contracts[2]	**1**	(1)	**2**	(5)
Commodity contracts[3]	**128**	157	**301**	104
Other contracts[4]	**2**	(2)	**7**	4
	609	(354)	**368**	(598)

1 *Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.*

2 *Reported as an increase to Interest expense in the Consolidated Statements of Earnings.*

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

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

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at June 30, 2014. 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 Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with the counterparties in these particular circumstances.

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

FAIR VALUE MEASUREMENTS

The Company uses the most observable inputs available to estimate the fair value of its derivatives. When possible, the Company estimates the fair value of its derivatives based on quoted market prices. If quoted market prices are not available, the Company uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share) 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.

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS

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

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Subsequently, the NEB issued revised "base case assumptions" based on feedback from member companies. Companies were given the option to follow the base case assumptions or to submit pipeline specific applications. On November 29, 2011, as required by the NEB, the Company filed its estimated abandonment costs for its regulated pipeline systems within Enbridge Pipelines Inc. and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc. and Enbridge Pipelines

(Westspur) Inc. (Group 2 companies). In the fourth quarter of 2012, the NEB held a hearing on the abandonment costs estimates for Group 1 companies and issued its decision on February 14, 2013. The outcome does not materially impact tolls. On February 28, 2013, Group 1 companies filed a proposed process and mechanism to set aside the funds for future abandonment costs and chose the qualified environmental trust as the appropriate set-aside mechanism to hold pipeline abandonment funds. On May 31, 2013, the Group 1 companies filed collection mechanism applications and the Group 2 companies filed both their set-aside and collection mechanism applications. Once the set-aside and collection mechanism is approved by the NEB, both Group 1 and Group 2 companies can start to recover these costs from shippers through tolls in accordance with the NEB's determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The collections are expected to begin in 2015.

All applications by the Company will require NEB approval. The NEB hearings commenced January 14, 2014, covering both the set-aside mechanism applications and the collection mechanism applications for both Group 1 and Group 2 companies. The NEB released its decision on May 29, 2014 approving both the set aside mechanism and collection mechanisms for all of the Enbridge Group 1 companies and Group 2 companies.

Currently, for the majority of the Company's assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

During the first half of 2014, the Company recognized ARO in the amount of $168 million. Of this amount, $64 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System in connection with the replacement work expected to occur in 2014 and $104 million related to the Canadian and United States portions of the L3R Program announced in March 2014.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

Parent's Accounting for the Cumulative Translation Adjustment

Effective January 1, 2014, the Company prospectively adopted ASU 2013-05 which provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. There was no material impact to the interim consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Revenue from Contracts with Customers

ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
ASU 2014-08 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

QUARTERLY FINANCIAL INFORMATION

	2014		2013				2012	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
(millions of Canadian dollars, except per share amounts)								
Revenues	**10,026**	10,521	8,293	8,998	7,730	7,897	7,007	5,676
Earnings attributable to common shareholders	**756**	390	(267)	421	42	250	146	187
Earnings per common share	**0.92**	0.48	(0.33)	0.52	0.05	0.32	0.19	0.24
Diluted earnings per common share	**0.91**	0.47	(0.32)	0.51	0.05	0.31	0.18	0.24
Dividends per common share	**0.3500**	0.3500	0.3150	0.3150	0.3150	0.3150	0.2825	0.2825
EGD - warmer/(colder) than normal weather	**(4)**	(33)	(13)	-	(2)	6	(1)	-
Changes in unrealized derivative fair value and intercompany foreign exchange (gains)/loss	**(430)**	190	613	(223)	246	207	81	93

Several factors impact comparability of the Company's financial results on a quarterly basis, including, but not limited to, seasonality in the Company's gas distribution businesses, fluctuations in market prices such as foreign exchange rates and commodity prices, disposals of investments or assets and the timing of in-service dates of new projects.

EGD and the Company's other gas distribution businesses are subject to seasonal demand. A significant portion of gas distribution customers use natural gas for space heating; therefore, volumes delivered and resulting revenues and earnings typically increase during the winter months of the first and fourth quarters of any given year. Revenues generated by EGD and other gas distribution businesses also vary from quarter-to-quarter with fluctuations in the price of natural gas, although earnings remain neutral due to the pass through nature of these costs.

The Company actively manages its exposure to market risks including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, changes in unrealized fair value gains and losses on these instruments will impact earnings.

In addition to the impacts of weather in EGD's franchise area and unrealized gains and losses outlined above, significant items that impacted the quarterly earnings included:

- First quarter earnings for 2014 included a $43 million after-tax gain on the disposal of non-core Offshore assets and a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment.
- Included in earnings are after-tax costs of $40 million, $13 million and $3 million incurred respectively in the second, third and fourth quarters of 2013, in connection with the Line 37 crude oil release which occurred in June 2013. Earnings also reflected insurance recoveries associated with the Line 37 crude oil release of $4 million recognized in the second quarter of 2014.
- Reflected in earnings is the Company's share of leak remediation costs associated with the Line 6B and Line 14 crude oil releases. Remediation costs of $5 million were recognized in the second quarter of 2014; $24 million, $6 million, $5 million and $9 million were recognized in the first, second, third and fourth quarters of 2013; and $7 million in the third quarter of 2012, respectively. Earnings

also reflected insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013 and $24 million in the third quarter of 2012, respectively.

- Fourth quarter earnings for 2012 included a $63 million, after-tax gain on recognition of a regulatory asset related to other postretirement benefits within EGD.
- Also included in the fourth quarter earnings for 2012 was an impairment charge of $166 million ($105 million after-tax) related to certain of its Offshore assets, predominantly located within the Stingray and Garden Banks corridors.
- Fourth quarter earnings for 2012 also included the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million incurred on the related capital gain.

Finally, the Company is in the midst of a substantial capital program and the timing of construction and completion of growth projects may impact the comparability of quarterly results. The Company's capital expansion initiatives, including construction commencement and in-service dates, are described in *Growth Projects – Commercially Secured Projects* and *Growth Projects – Other Projects Under Development.*

NON-GAAP RECONCILIATIONS

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Earnings attributable to common shareholders	**756**	42	**1,146**	292
Adjusting items:				
Liquids Pipelines				
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss[1]	**(211)**	186	**(39)**	258
Canadian Mainline - Line 9B costs incurred during reversal	**4**	-	**4**	-
Regional Oil Sands System - make-up rights adjustment	**(2)**	-	**-**	-
Regional Oil Sands System - leak insurance recoveries	**(4)**	-	**(4)**	-
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**-**	40	**-**	40
Spearhead Pipeline - make-up rights adjustment	**1**	-	**1**	-
Feeder Pipelines and Other - make-up rights adjustment	**(2)**	-	**(2)**	-
Feeder Pipelines and Other - project development costs	**3**	-	**3**	-
Gas Distribution				
EGD - warmer/(colder) than normal weather	**(4)**	(2)	**(37)**	4
Gas Pipelines, Processing and Energy Services				
Energy Services - changes in unrealized derivative fair value gains[1]	**(81)**	(143)	**(217)**	(113)
Offshore - gain on sale of non-core assets	**-**	-	**(43)**	-
Other - changes in unrealized derivative fair value loss[1]	**1**	56	**2**	56
Sponsored Investments				
EEP - changes in unrealized derivative fair value (gains)/loss[1]	**3**	(4)	**3**	(3)
EEP - make-up rights adjustment	**1**	-	**1**	-
EEP - leak remediation costs	**5**	6	**5**	30
EEP - leak insurance recoveries	**-**	(6)	**-**	(6)
EEP - tax rate differences/changes	**-**	3	**-**	3
Corporate				
Noverco - changes in unrealized derivative fair value loss[1]	**1**	2	**5**	1
Other Corporate - changes in unrealized derivative fair value (gains)/loss[1]	**(143)**	149	**6**	254
Other Corporate - gain on sale of investment	**-**	-	**(14)**	-
Other Corporate - foreign tax recovery	**-**	-	**-**	(4)
Other Corporate - impact of tax rate changes	**-**	(23)	**-**	(18)
Adjusted earnings	**328**	306	**820**	794

1 Changes in unrealized derivative fair value gains and losses are presented net of amounts realized on the settlement of derivative contracts during the applicable period.

OUTSTANDING SHARE DATA[1]

PREFERENCE SHARES

	Number	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3]
Preference Shares, Series A	5,000,000	-	-
Preference Shares, Series B	20,000,000	June 1, 2017	Series C
Preference Shares, Series D	18,000,000	March 1, 2018	Series E
Preference Shares, Series F	20,000,000	June 1, 2018	Series G
Preference Shares, Series H	14,000,000	September 1, 2018	Series I
Preference Shares, Series J	8,000,000	June 1, 2017	Series K
Preference Shares, Series L	16,000,000	September 1, 2017	Series M
Preference Shares, Series N	18,000,000	December 1, 2018	Series O
Preference Shares, Series P	16,000,000	March 1, 2019	Series Q
Preference Shares, Series R	16,000,000	June 1, 2019	Series S
Preference Shares, Series 1	16,000,000	June 1, 2018	Series 2
Preference Shares, Series 3	24,000,000	September 1, 2019	Series 4
Preference Shares, Series 5	8,000,000	March 1, 2019	Series 6
Preference Shares, Series 7	10,000,000	March 1, 2019	Series 8
Preference Shares, Series 9	11,000,000	December 1, 2019	Series 10
Preference Shares, Series 11	20,000,000	March 1, 2020	Series 12
Preference Shares, Series 13	14,000,000	June 1, 2020	Series 14

COMMON SHARES

	Number
Common Shares - issued and outstanding (voting equity shares)	846,245,431
Stock Options - issued and outstanding (19,353,324 vested)	37,636,492

1 *Outstanding share data information is provided as at July 18, 2014.*

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

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

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**7,484**	6,155	**15,490**	11,959
Gas distribution sales	**598**	394	**1,709**	1,285
Transportation and other services	**1,944**	1,181	**3,348**	2,383
	10,026	7,730	**20,547**	15,627
Expenses				
Commodity costs	**7,386**	5,856	**15,119**	11,468
Gas distribution costs	**337**	212	**1,183**	878
Operating and administrative	**814**	796	**1,559**	1,460
Depreciation and amortization	**393**	334	**759**	656
Environmental costs, net of recoveries *(Note 13)*	**36**	56	**41**	239
	8,966	7,254	**18,661**	14,701
	1,060	476	**1,886**	926
Income from equity investments	**65**	64	**179**	165
Other income/(expense)	**215**	(169)	**77**	(217)
Interest expense	**(231)**	(204)	**(469)**	(459)
	1,109	167	**1,673**	415
Income taxes *(Note 11)*	**(276)**	(41)	**(393)**	(103)
Earnings from continuing operations	**833**	126	**1,280**	312
Discontinued operations *(Note 4)*				
Earnings from discontinued operations before income taxes	**-**	-	**73**	-
Income taxes from discontinued operations	**-**	-	**(27)**	-
Earnings from discontinued operations	**-**	-	**46**	-
Earnings	**833**	126	**1,326**	312
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(18)**	(41)	**(66)**	62
Earnings attributable to Enbridge Inc.	**815**	85	**1,260**	374
Preference share dividends	**(59)**	(43)	**(114)**	(82)
Earnings attributable to Enbridge Inc. common shareholders	**756**	42	**1,146**	292
Earnings attributable to Enbridge Inc. common shareholders				
Earnings from continuing operations	**756**	42	**1,100**	292
Earnings from discontinued operations, net of tax	**-**	-	**46**	-
	756	42	**1,146**	292
Earnings per common share attributable to Enbridge Inc. commc shareholders *(Note 8)*				
Continuing operations	**0.92**	0.05	**1.34**	0.37
Discontinued operations	**-**	-	**0.05**	-
	0.92	0.05	**1.39**	0.37
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 8)*				
Continuing operations	**0.91**	0.05	**1.33**	0.36
Discontinued operations	**-**	-	**0.05**	-
	0.91	0.05	**1.38**	0.36

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(unaudited; millions of Canadian dollars)				
Earnings	**833**	126	**1,326**	312
Other comprehensive income/(loss), net of tax				
Change in unrealized gains/(loss) on cash flow hedges	**(210)**	507	**(514)**	584
Change in unrealized gains/(loss) on net investment hedges	**98**	(50)	**9**	(74)
Other comprehensive income from equity investees	**3**	4	**7**	6
Reclassification to earnings of realized cash flow hedges	**35**	25	**75**	35
Reclassification to earnings of unrealized cash flow hedges	**4**	(13)	**24**	15
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**2**	8	**3**	17
Change in foreign currency translation adjustment	**(507)**	342	**16**	529
Other comprehensive income/(loss)	**(575)**	823	**(380)**	1,112
Comprehensive income	**258**	949	**946**	1,424
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**168**	(274)	**27**	(256)
Comprehensive income attributable to Enbridge Inc.	**426**	675	**973**	1,168
Preference share dividends	**(59)**	(43)	**(114)**	(82)
Comprehensive income attributable to Enbridge Inc. common shareholders	**367**	632	**859**	1,086

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Six months ended June 30,	
	2014	2013
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 8)*		
Balance at beginning of period	**5,141**	3,707
Preference shares issued	**762**	992
Balance at end of period	**5,903**	4,699
Common shares		
Balance at beginning of period	**5,744**	4,732
Shares issued	**388**	586
Dividend reinvestment and share purchase plan	**212**	176
Shares issued on exercise of stock options	**30**	51
Balance at end of period	**6,374**	5,545
Additional paid-in capital		
Balance at beginning of period	**746**	522
Stock-based compensation	**19**	19
Options exercised	**(8)**	(13)
Issuance of treasury stock	**-**	208
Dilution gains and other	**(4)**	4
Balance at end of period	**753**	740
Retained earnings		
Balance at beginning of period	**2,550**	3,173
Earnings attributable to Enbridge Inc.	**1,260**	374
Preference share dividends	**(114)**	(82)
Common share dividends declared	**(584)**	(513)
Dividends paid to reciprocal shareholder	**9**	9
Redemption value adjustment attributable to redeemable noncontrolling interests	**(230)**	(37)
Balance at end of period	**2,891**	2,924
Accumulated other comprehensive loss *(Note 9)*		
Balance at beginning of period	**(599)**	(1,762)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(287)**	794
Balance at end of period	**(886)**	(968)
Reciprocal shareholding		
Balance at beginning of period	**(86)**	(126)
Issuance of treasury stock	**-**	40
Balance at end of period	**(86)**	(86)
Total Enbridge Inc. shareholders' equity	**14,949**	12,854
Noncontrolling interests		
Balance at beginning of period	**4,014**	3,258
Earnings/(loss) attributable to noncontrolling interests	**61**	(51)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**(133)**	132
Change in foreign currency translation adjustment	**24**	172
Reclassification to earnings of realized cash flow hedges	**16**	13
Reclassification to earnings of unrealized cash flow hedges	**8**	(2)
	(85)	315
Comprehensive income/(loss) attributable to noncontrolling interests	**(24)**	264
Contributions	**81**	280
Distributions	**(260)**	(228)
Other	**(4)**	9
Balance at end of period	**3,807**	3,583
Total equity	**18,756**	16,437
Dividends paid per common share	**0.70**	0.63

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings	**833**	126	**1,326**	312
Earnings from discontinued operations	**-**	-	**(46)**	-
Depreciation and amortization	**393**	334	**759**	656
Deferred income taxes	**277**	70	**346**	71
Changes in unrealized (gains)/loss on derivative instruments, net	**(607)**	358	**(363)**	606
Cash distributions in excess of equity earnings	**37**	242	**49**	211
Gain on disposition	**-**	-	**(16)**	-
Other	**6**	-	**68**	65
Changes in regulatory assets and liabilities	**10**	8	**15**	20
Changes in environmental liabilities, net of recoveries *(Note 13)*	**10**	40	**(36)**	201
Changes in operating assets and liabilities	**(147)**	(241)	**(976)**	(412)
Cash provided by continuing operations	**812**	937	**1,126**	1,730
Cash provided by discontinued operations *(Note 4)*	**-**	-	**19**	-
	812	937	**1,145**	1,730
Investing activities				
Additions to property, plant and equipment	**(2,635)**	(1,599)	**(5,043)**	(3,056)
Long-term investments	**(212)**	(295)	**(525)**	(423)
Additions to intangible assets	**(58)**	(60)	**(111)**	(111)
Proceeds from disposition	**-**	-	**19**	-
Affiliate loans, net	**3**	1	**6**	3
Changes in restricted cash	**16**	4	**21**	(5)
Cash provided by continuing operations	**(2,886)**	(1,949)	**(5,633)**	(3,592)
Cash provided by discontinued operations *(Note 4)*	**-**	-	**4**	-
	(2,886)	(1,949)	**(5,629)**	(3,592)
Financing activities				
Net change in bank indebtedness and short-term borrowings	**83**	358	**444**	146
Net change in commercial paper and credit facility draws	**377**	(250)	**1,215**	129
Net change in Southern Lights project financing	**-**	(5)	**-**	(5)
Debenture and term note issues	**1,928**	-	**3,456**	-
Debenture and term note repayments	**(425)**	(210)	**(625)**	(410)
Contributions from noncontrolling interests	**40**	5	**81**	280
Distributions to noncontrolling interests	**(130)**	(114)	**(260)**	(228)
Contributions from redeemable noncontrolling interests	**-**	-	**-**	91
Distributions to redeemable noncontrolling interests	**(19)**	(18)	**(37)**	(36)
Preference shares issued	**490**	587	**758**	986
Common shares issued	**390**	592	**406**	614
Preference share dividends	**(57)**	(41)	**(111)**	(79)
Common share dividends	**(187)**	(173)	**(372)**	(337)
	2,490	731	**4,955**	1,151
Effect of translation of foreign denominated cash and cash equivalents	**(17)**	12	**1**	12
Increase/(decrease) in cash and cash equivalents	**399**	(269)	**472**	(699)
Cash and cash equivalents at beginning of period - discontinued operations	**-**	-	**20**	-
Cash and cash equivalents at beginning of period - continuing operations	**849**	1,346	**756**	1,776
Cash and cash equivalents at end of period	**1,248**	1,077	**1,248**	1,077

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2014	December 31, 2013
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,248**	756
Restricted cash	**13**	34
Accounts receivable and other *(Note 5)*	**4,701**	4,956
Accounts receivable from affiliates	**122**	65
Inventory	**1,250**	1,115
Assets held for sale *(Note 4)*	**-**	24
	7,334	6,950
Property, plant and equipment, net	**46,433**	42,279
Long-term investments	**4,691**	4,212
Deferred amounts and other assets	**2,906**	2,662
Intangible assets, net	**1,069**	1,004
Goodwill	**447**	445
Deferred income taxes	**127**	16
	63,007	57,568
Liabilities and equity		
Current liabilities		
Bank indebtedness	**453**	338
Short-term borrowings	**703**	374
Accounts payable and other	**5,849**	6,664
Accounts payable to affiliates	**35**	46
Interest payable	**239**	228
Environmental liabilities	**202**	260
Current maturities of long-term debt *(Note 6)*	**2,510**	2,811
Liabilities held for sale *(Note 4)*	**-**	7
	9,991	10,728
Long-term debt *(Note 6)*	**26,710**	22,357
Other long-term liabilities	**2,973**	2,938
Deferred income taxes	**3,334**	2,925
Liabilities held for sale *(Note 4)*	**-**	57
	43,008	39,005
Contingencies *(Note 13)*		
Redeemable noncontrolling interests	**1,243**	1,053
Equity		
Share capital		
Preference shares *(Note 8)*	**5,903**	5,141
Common shares (845 and 831 outstanding at June 30, 2014 and December 31, 2013, respectively)	**6,374**	5,744
Additional paid-in capital	**753**	746
Retained earnings	**2,891**	2,550
Accumulated other comprehensive loss *(Note 9)*	**(886)**	(599)
Reciprocal shareholding	**(86)**	(86)
Total Enbridge Inc. shareholders' equity	**14,949**	13,496
Noncontrolling interests	**3,807**	4,014
	18,756	17,510
	63,007	57,568

See accompanying notes to the unaudited interim consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2013. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the Company's financial position as at June 30, 2014 and results of operations and cash flows for the three and six months ended June 30, 2014 and 2013. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company's consolidated financial statements as at and for the year ended December 31, 2013, except for the adoption of new standards *(Note 2)*. Amounts are stated in Canadian dollars unless otherwise noted.

The Company's operations and earnings for interim periods can be affected by seasonal fluctuations within the gas distribution utility business, as well as other factors such as the supply of and demand for crude oil and natural gas.

2. SIGNIFICANT ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Obligations Resulting from Joint and Several Liability Arrangements

Effective January 1, 2014, the Company retrospectively adopted Accounting Standards Update (ASU) 2013-04 which provides measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. There was no material impact to the consolidated financial statements for the current or prior periods presented as a result of adopting this update.

Parent's Accounting for the Cumulative Translation Adjustment

Effective January 1, 2014, the Company prospectively adopted ASU 2013-05 which provides guidance on the timing of release of the cumulative translation adjustment into net income when a disposition or ownership change occurs related to an investment in a foreign entity or a business within a foreign entity. There was no material impact to the interim consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Revenue from Contracts with Customers

ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

ASU 2014-08 was issued in April 2014 and changes the criteria and disclosures for reporting discontinued operations. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2014 and is to be applied prospectively.

3. SEGMENTED INFORMATION

Three months ended June 30, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**991**	**629**	**6,286**	**2,120**	**-**	**10,026**
Commodity and gas distribution costs	**-**	**(337)**	**(6,050)**	**(1,336)**	**-**	**(7,723)**
Operating and administrative	**(279)**	**(137)**	**(50)**	**(341)**	**(7)**	**(814)**
Depreciation and amortization	**(121)**	**(88)**	**(23)**	**(156)**	**(5)**	**(393)**
Environmental costs, net of recoveries	**7**	**-**	**-**	**(43)**	**-**	**(36)**
	598	**67**	**163**	**244**	**(12)**	**1,060**
Income/(loss) from equity investments	**39**	**-**	**29**	**17**	**(20)**	**65**
Other income/(expense)	**2**	**(1)**	**4**	**(1)**	**211**	**215**
Interest income/(expense)	**(87)**	**(40)**	**(25)**	**(110)**	**31**	**(231)**
Income taxes expense	**(120)**	**(7)**	**(64)**	**(46)**	**(39)**	**(276)**
Earnings	**432**	**19**	**107**	**104**	**171**	**833**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**-**	**(17)**	**-**	**(18)**
Preference share dividends	**-**	**-**	**-**	**-**	**(59)**	**(59)**
Earnings attributable to Enbridge Inc. common shareholders	**431**	**19**	**107**	**87**	**112**	**756**
Additions to property, plant and equipment[2]	**1,516**	**111**	**211**	**787**	**10**	**2,635**

Three months ended June 30, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	323	495	5,135	1,777	-	7,730
Commodity and gas distribution costs	-	(212)	(4,749)	(1,107)	-	(6,068)
Operating and administrative	(252)	(135)	(120)	(282)	(7)	(796)
Depreciation and amortization	(103)	(79)	(16)	(131)	(5)	(334)
Environmental costs, net of recoveries	(51)	-	-	(5)	-	(56)
	(83)	69	250	252	(12)	476
Income/(loss) from equity investments	36	-	31	14	(17)	64
Other income/(expense)	10	1	5	7	(192)	(169)
Interest income/(expense)	(73)	(38)	(20)	(98)	25	(204)
Income taxes recovery/(expense)	44	(5)	(106)	(63)	89	(41)
Earnings/(loss)	(66)	27	160	112	(107)	126
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	(40)	-	(41)
Preference share dividends	-	-	-	-	(43)	(43)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	(67)	27	160	72	(150)	42
Additions to property, plant and equipment[2]	863	118	128	485	5	1,599

Six months ended June 30, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**1,438**	**1,914**	**12,708**	**4,487**	**-**	**20,547**
Commodity and gas distribution costs	**-**	**(1,183)**	**(12,169)**	**(2,950)**	**-**	**(16,302)**
Operating and administrative	**(535)**	**(270)**	**(84)**	**(664)**	**(6)**	**(1,559)**
Depreciation and amortization	**(238)**	**(172)**	**(35)**	**(305)**	**(9)**	**(759)**
Environmental costs, net of recoveries	**7**	**-**	**-**	**(48)**	**-**	**(41)**
	672	**289**	**420**	**520**	**(15)**	**1,886**
Income/(loss) from equity investments	**75**	**-**	**78**	**35**	**(9)**	**179**
Other income/(expense)	**3**	**2**	**9**	**(2)**	**65**	**77**
Interest income/(expense)	**(174)**	**(80)**	**(43)**	**(221)**	**49**	**(469)**
Income taxes recovery/(expense)	**(99)**	**(56)**	**(166)**	**(97)**	**25**	**(393)**
Earnings from continuing operations	**477**	**155**	**298**	**235**	**115**	**1,280**
Discontinued operations						
Earnings from discontinued operations before income tax	**-**	**-**	**73**	**-**	**-**	**73**
Income taxes from discontinued operations	**-**	**-**	**(27)**	**-**	**-**	**(27)**
Earnings from discontinued operations	**-**	**-**	**46**	**-**	**-**	**46**
Earnings	**477**	**155**	**344**	**235**	**115**	**1,326**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(2)**	**-**	**-**	**(64)**	**-**	**(66)**
Preference share dividends	**-**	**-**	**-**	**-**	**(114)**	**(114)**
Earnings attributable to Enbridge Inc. common shareholders	**475**	**155**	**344**	**171**	**1**	**1,146**
Additions to property, plant and equipment[2]	**3,014**	**208**	**329**	**1,469**	**24**	**5,044**

Six months ended June 30, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	867	1,561	9,658	3,541	-	15,627
Commodity and gas distribution costs	-	(878)	(9,197)	(2,271)	-	(12,346)
Operating and administrative	(490)	(269)	(161)	(542)	2	(1,460)
Depreciation and amortization	(203)	(158)	(31)	(255)	(9)	(656)
Environmental costs, net of recoveries	(51)	-	-	(188)	-	(239)
	123	256	269	285	(7)	926
Income from equity investments	61	-	64	27	13	165
Other income/(expense)	20	2	20	4	(263)	(217)
Interest expense	(144)	(78)	(38)	(191)	(8)	(459)
Income taxes recovery/(expense)	22	(46)	(126)	(75)	122	(103)
Earnings/(loss)	82	134	189	50	(143)	312
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(2)	-	-	64	-	62
Preference share dividends	-	-	-	-	(82)	(82)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	80	134	189	114	(225)	292
Additions to property, plant and equipment[2]	1,630	221	266	930	9	3,056

1 *Included within the Corporate segment was Interest income of $161 million and $316 million for the three and six months ended June 30, 2014, respectively, (2013 - $101 million and $193 million, respectively) charged to other operating segments.*

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

The Company has downwardly revised both Commodity sales and Commodity costs by $117 million and $237 million for the three and six months ended June 30, 2013 relating to a correction to intercompany transactions within the Gas Pipelines, Processing and Energy Services segment, as discussed in Note 4 to the consolidated financial statements for the year ended December 31, 2013. This presentation matter had no net effect on the margin, earnings or cash flows for the period.

TOTAL ASSETS

(millions of Canadian dollars)	**June 30, 2014**	December 31, 2013
Liquids Pipelines	**24,245**	20,950
Gas Distribution	**8,547**	7,942
Gas Pipelines, Processing and Energy Services	**6,906**	7,015
Sponsored Investments	**19,798**	18,527
Corporate	**3,511**	3,134
	63,007	57,568

4. DISCONTINUED OPERATIONS

Effective March 1, 2014, the Company completed the sale of certain of its Enbridge Offshore Pipelines assets located within the Stingray corridor to an unrelated third party for cash proceeds of $11 million (US$10 million), subject to working capital adjustments. The gain of $70 million (US$63 million), which resulted from the cash proceeds and the disposition of net liabilities held for sale of $59 million (US$53 million), is presented as Earnings from discontinued operations. The results of operations, including revenues of $4 million and related cash flows, have also been presented as discontinued operations for the six months ended June 30, 2014. These amounts are included within the Gas Pipelines, Processing and Energy Services segment.

5. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain Enbridge Energy Partners, L.P. (EEP) subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis through to December 2016, provided accumulated purchases net of collections do not exceed US$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US$408 million ($436 million) and US$380 million ($404 million) as at June 30, 2014 and December 31, 2013, respectively.

6. DEBT

During the six months ended June 30, 2014, the Company completed aggregate issuances of unsecured, medium-term notes of $1,830 million and senior notes of US$1,500 million which carry interest rates of 0.7% to 4.6% and have maturities ranging from three to 30 years, with the exception of $130 million that matures in 50 years.

CREDIT FACILITIES

The following table provides details of the Company's committed credit facilities at June 30, 2014 and December 31, 2013.

		June 30, 2014			December 31, 2013
	Maturity Dates	Total Facilities	Draws[2]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2015	**300**	**196**	**104**	300
Gas Distribution	2016-2019	**1,008**	**708**	**300**	713
Sponsored Investments	2015-2018	**4,797**	**1,831**	**2,966**	4,781
Corporate	2015-2018	**11,947**	**3,986**	**7,961**	11,805
		18,052	**6,721**	**11,331**	17,599
Southern Lights project financing[1]	2014-2015	**1,574**	**1,502**	**72**	1,570
Total committed credit facilities		**19,626**	**8,223**	**11,403**	19,169

1 *Total facilities are inclusive of $63 million for debt service reserve letters of credit.*

2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*

In addition to the committed credit facilities noted above, the Company also has $269 million of uncommitted demand credit facilities, of which $250 million was unutilized as at June 30, 2014.

Subsequent to June 30, 2014, the Company has extended the maturity of a number of credit facilities for another year and increased committed credit facilities by $75 million.

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2014 to 2019.

Commercial paper and credit facility draws, net of short-term borrowings, of $5,803 million (December 31, 2013 - $4,580 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

7. ASSET RETIREMENT OBLIGATIONS

During the six months ended June 30, 2014, the Company recognized asset retirement obligations (ARO) in the amount of $168 million. Of the amount, $64 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System in connection with the replacement work expected to occur in 2014 and $104 million related to the Canadian and United States portions of the Line 3 Replacement Program announced in March 2014.

The Company records ARO at fair value in the period in which they can be reasonably determined. Fair value is determined based on expected future cash flows and estimated retirement periods, as well as discount and inflation rates. As at June 30, 2014, ARO of $64 million were classified within Accounts payable and other and $104 million were classified within Other long-term liabilities, with an offset to Property, plant and equipment on the Consolidated Statements of Financial Position.

8. SHARE CAPITAL

PREFERENCE SHARES

	June 30, 2014		December 31, 2013	
	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
Preference Shares, Series B	**20**	**500**	20	500
Preference Shares, Series D	**18**	**450**	18	450
Preference Shares, Series F	**20**	**500**	20	500
Preference Shares, Series H	**14**	**350**	14	350
Preference Shares, Series J	**8**	**199**	8	199
Preference Shares, Series L	**16**	**411**	16	411
Preference Shares, Series N	**18**	**450**	18	450
Preference Shares, Series P	**16**	**400**	16	400
Preference Shares, Series R	**16**	**400**	16	400
Preference Shares, Series 1	**16**	**411**	16	411
Preference Shares, Series 3	**24**	**600**	24	600
Preference Shares, Series 5	**8**	**206**	8	206
Preference Shares, Series 7	**10**	**250**	10	250
Preference Shares, Series 9	**11**	**275**	-	-
Preference Shares, Series 11	**20**	**500**	-	-
Issuance costs		**(124)**		(111)
Balance at end of period		**5,903**		5,141

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.5%	$1.375	$25	-	-
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.0%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R	4.0%	$1.000	$25	June 1, 2019	Series S
Preference Shares, Series 1	4.0%	US$1.000	US$25	June 1, 2018	Series 2
Preference Shares, Series 3	4.0%	$1.000	$25	September 1, 2019	Series 4
Preference Shares, Series 5	4.4%	US$1.100	US$25	March 1, 2019	Series 6
Preference Shares, Series 7	4.4%	$1.100	$25	March 1, 2019	Series 8
Preference Shares, Series 9	4.4%	$1.100	$25	December 1, 2019	Series 10
Preference Shares, Series 11[5]	4.4%	$1.100	$25	March 1, 2020	Series 12

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

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

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

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10) or 2.6%*

(Series 12); or US$25 x (number of days in quarter/365) x (three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6)).

5 A cash dividend of $0.3074 per share will be payable on September 1, 2014 to Series 11 shareholders. The regular quarterly dividend of $0.275 per share takes effect on December 1, 2014.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 12 million (2013 - 16 million and 17 million) for the three and six months ended June 30, 2014, resulting from the Company's reciprocal investment in Noverco Inc.

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.

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(number of shares in millions)				
Weighted average shares outstanding	**824**	806	**822**	797
Effect of dilutive options	**10**	11	**10**	12
Diluted weighted average shares outstanding	**834**	817	**832**	809

For the three and six months ended June 30, 2014, 5,945,800 and 7,183,912 anti-dilutive stock options (2013 - 6,353,550) with a weighted average exercise price of $48.80 and $48.12 (2013 - $44.85) were excluded from the diluted earnings per common share calculation.

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in Accumulated other comprehensive loss (AOCI) attributable to Enbridge common shareholders for the six months ended June 30, 2014 and 2013 are as follows:

	Cash Flow Hedges	Net Investment Hedges[6]	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2014	**(1)**	**378**	**(778)**	**(15)**	**(183)**	**(599)**
Other comprehensive income/(loss) retained in AOCI	**(514)**	**10**	**(8)**	**7**	**-**	**(505)**
Other comprehensive gains reclassified to earnings						
Interest rate contracts[1]	**55**	**-**	**-**	**-**	**-**	**55**
Commodity contracts[2]	**7**	**-**	**-**	**-**	**-**	**7**
Foreign exchange contracts[3]	**15**	**-**	**-**	**-**	**-**	**15**
Other contracts[4]	**9**	**-**	**-**	**-**	**-**	**9**
Amortization of pension and OPEB actuarial loss[5]	**-**	**-**	**-**	**-**	**6**	**6**
	(428)	**10**	**(8)**	**7**	**6**	**(413)**
Tax impact						
Income tax on amounts retained in AOCI	**141**	**(1)**	**-**	**-**	**-**	**140**
Income tax on amounts reclassified to earnings	**(11)**	**-**	**-**	**-**	**(3)**	**(14)**
	130	**(1)**	**-**	**-**	**(3)**	**126**
Balance at June 30, 2014	**(299)**	**387**	**(786)**	**(8)**	**(180)**	**(886)**

	Cash Flow Hedges	Net Investment Hedges[6]	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2013	(621)	474	(1,265)	(26)	(324)	(1,762)
Other comprehensive income/(loss) retained in AOCI	609	(86)	357	6	-	886
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	53	-	-	-	-	53
Commodity contracts[2]	(1)	-	-	-	-	(1)
Foreign exchange contracts[3]	(3)	-	-	-	-	(3)
Amortization of pension and OPEB actuarial loss[5]	-	-	-	-	23	23
	658	(86)	357	6	23	958
Tax impact						
Income tax on amounts retained in AOCI	(160)	12	-	-	-	(148)
Income tax on amounts reclassified to earnings	(10)	-	-	-	(6)	(16)
	(170)	12	-	-	(6)	(164)
Balance at June 30, 2013	(133)	400	(908)	(20)	(307)	(968)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
3 *Reported within Other income/(expense) in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
5 *These components are included in the computation of net periodic pension costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
6 *Other comprehensive income/(loss) retained in AOCI includes a $10 million unrealized gain (2013 - $17 million unrealized loss) on foreign currency translation of United States dollar denominated long-term debt designated as a hedge of net investments in United States dollar denominated investments and subsidiaries.*

10. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

The Company's earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and the Company's share price (collectively, market risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market risks to which the Company is exposed and the risk management instruments used to mitigate them. 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, certain revenues denominated in United States dollars and certain expenses denominated in Euros. The Company has implemented a policy whereby, at a minimum, it economically hedges a level of foreign currency denominated earnings exposures identified over a five year forecast horizon. The Company may also hedge anticipated foreign currency denominated purchases or sales and 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. The Company has designated a portion of its United States dollar denominated long-term debt and certain derivative foreign exchange contracts as hedges of net investments in United States dollar denominated investments and subsidiaries.

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 2019 through execution of floating to fixed interest rate swaps with an average swap rate of 2.1%.

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 2017. A total of $8,870 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.6%.

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

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

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

TOTAL DERIVATIVE INSTRUMENTS
The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges at June 30, 2014 or December 31, 2013.

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

June 30, 2014	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**3**	**11**	**38**	**52**	**(26)**	**26**
Interest rate contracts	**36**	**-**	**7**	**43**	**(8)**	**35**
Commodity contracts	**1**	**-**	**81**	**82**	**(37)**	**45**
Other contracts	**1**	**-**	**9**	**10**	**-**	**10**
	41	**11**	**135**	**187**	**(71)**	**116**
Deferred amounts and other assets						
Foreign exchange contracts	**6**	**29**	**13**	**48**	**(45)**	**3**
Interest rate contracts	**78**	**-**	**-**	**78**	**(20)**	**58**
Commodity contracts	**3**	**-**	**23**	**26**	**(15)**	**11**
Other contracts	**3**	**-**	**2**	**5**	**-**	**5**
	90	**29**	**38**	**157**	**(80)**	**77**
Accounts payable and other						
Foreign exchange contracts	**(2)**	**(16)**	**(62)**	**(80)**	**26**	**(54)**
Interest rate contracts	**(353)**	**-**	**(9)**	**(362)**	**11**	**(351)**
Commodity contracts	**(11)**	**-**	**(210)**	**(221)**	**37**	**(184)**
	(366)	**(16)**	**(281)**	**(663)**	**74**	**(589)**
Other long-term liabilities						
Foreign exchange contracts	**(6)**	**(18)**	**(357)**	**(381)**	**45**	**(336)**
Interest rate contracts	**(259)**	**-**	**-**	**(259)**	**17**	**(242)**
Commodity contracts	**(1)**	**-**	**(592)**	**(593)**	**15**	**(578)**
	(266)	**(18)**	**(949)**	**(1,233)**	**77**	**(1,156)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**1**	**6**	**(368)**	**(361)**	**-**	**(361)**
Interest rate contracts	**(498)**	**-**	**(2)**	**(500)**	**-**	**(500)**
Commodity contracts	**(8)**	**-**	**(698)**	**(706)**	**-**	**(706)**
Other contracts	**4**	**-**	**11**	**15**	**-**	**15**
	(501)	**6**	**(1,057)**	**(1,552)**	**-**	**(1,552)**

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

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

June 30, 2014	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**307**	**25**	**25**	**413**	**2**	**4**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,936**	**2,751**	**2,323**	**2,557**	**1,714**	**3,771**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	**2**	**28**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**2,612**	**5,222**	**5,013**	**4,048**	**2,443**	**639**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**4,184**	**1,780**	**1,816**	**1,090**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**45**	**45**	**48**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(78)**	**(50)**	**(20)**	**(13)**	**-**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**(3)**	**(23)**	**(24)**	**(18)**	**(9)**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(17)**	**(6)**	**(1)**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**39**	**5**	**20**	**40**	**30**	**8**

December 31, 2013	2014	2015	2016	2017	2018	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	710	25	25	413	2	4
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,795	2,751	2,323	2,557	1,649	3,771
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	5	28	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	5,007	5,210	5,030	3,965	274	267
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	5,736	1,779	1,814	1,090	-	-
Equity contracts *(millions of Canadian dollars)*	40	41	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	17	(8)	10	11	46	-
Commodity contracts - crude oil *(millions of barrels)*	(34)	(29)	(23)	(18)	(9)	-
Commodity contracts - NGL *(millions of barrels)*	(10)	(2)	-	-	-	-
Commodity contracts - power *(MWH)*	55	5	20	40	30	8

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

The following table presents the effect of cash flow hedges and net investment hedges on the Company's consolidated earnings and consolidated comprehensive income, before the effect of income taxes.

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Amount of unrealized gains/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(60)**	33	**(31)**	47
Interest rate contracts	**(279)**	710	**(521)**	789
Commodity contracts	**(10)**	17	**(17)**	17
Other contracts	**3**	(3)	**8**	(1)
Net investment hedges				
Foreign exchange contracts	**45**	(45)	**(3)**	(67)
	(301)	712	**(564)**	785
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*				
Foreign exchange contracts[1]	**16**	(3)	**15**	(3)
Interest rate contracts[2]	**23**	33	**44**	46
Commodity contracts[3]	**5**	(4)	**12**	(4)
Other contracts[4]	**(3)**	-	**(7)**	-
	41	26	**64**	39
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**3**	(15)	**28**	23
Commodity contracts[3]	**2**	(1)	**3**	(2)
	5	(16)	**31**	21

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

The Company estimates that $71 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 54 months at June 30, 2014.

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.

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**478**	(508)	**58**	(701)
Interest rate contracts[2]	**1**	(1)	**2**	(5)
Commodity contracts[3]	**128**	157	**301**	104
Other contracts[4]	**2**	(2)	**7**	4
Total unrealized derivative fair value gains/(loss)	**609**	(354)	**368**	(598)

1 *Reported within Transportation and other services revenues (2014 - $56 million gain; 2013 - $376 million loss) and Other income/(expense) (2014 - $2 million gain; 2013 - $325 million loss) in the Consolidated Statements of Earnings.*

2 *Reported as an (increase)/decrease to Interest expense in the Consolidated Statements of Earnings.*

3 *Reported within Transportation and other services revenues (2014 - $305 million gain; 2013 - $170 million gain), Commodity costs (2014 - $1 million loss; 2013 - $6 million gain) and Operating and administrative expense (2014 - $3 million loss; 2013 - $72 million loss) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at June 30, 2014. 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 had group credit concentrations and maximum credit exposure, with respect to derivative instruments, in the following counterparty segments:

	June 30, 2014	December 31, 2013
(millions of Canadian dollars)		
Canadian financial institutions	**125**	230
United States financial institutions	**46**	227
European financial institutions	**70**	192
Other[1]	**74**	97
	315	746

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

As at June 30, 2014, the Company had provided letters of credit totalling $170 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held $4 million of cash collateral on derivative asset exposures at June 30, 2014 and $18 million of cash collateral at December 31, 2013.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of the Company's counterparties using their credit default swap spread rates, and are reflected in the fair value. For derivative liabilities, the Company's non-performance risk is considered in the valuation.

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

Level 2

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

The Company has also categorized the fair value of its held to maturity preferred share investment and long-term debt as Level 2. The fair value of the Company's held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The

Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. The Company does not have any other financial instruments categorized in Level 3.

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

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

June 30, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**52**	**-**	**52**
Interest rate contracts	**-**	**43**	**-**	**43**
Commodity contracts	**1**	**19**	**62**	**82**
Other contracts	**-**	**10**	**-**	**10**
	1	**124**	**62**	**187**
Long-term derivative assets				
Foreign exchange contracts	**-**	**48**	**-**	**48**
Interest rate contracts	**-**	**78**	**-**	**78**
Commodity contracts	**-**	**9**	**17**	**26**
Other contracts	**-**	**5**	**-**	**5**
	-	**140**	**17**	**157**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(80)**	**-**	**(80)**
Interest rate contracts	**-**	**(362)**	**-**	**(362)**
Commodity contracts	**(4)**	**(126)**	**(91)**	**(221)**
	(4)	**(568)**	**(91)**	**(663)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(381)**	**-**	**(381)**
Interest rate contracts	**-**	**(259)**	**-**	**(259)**
Commodity contracts	**-**	**(433)**	**(160)**	**(593)**
	-	**(1,073)**	**(160)**	**(1,233)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(361)**	**-**	**(361)**
Interest rate contracts	**-**	**(500)**	**-**	**(500)**
Commodity contracts	**(3)**	**(531)**	**(172)**	**(706)**
Other contracts	**-**	**15**	**-**	**15**
	(3)	**(1,377)**	**(172)**	**(1,552)**

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

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

June 30, 2014	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	3	Forward gas price	3.95	5.25	4.60	$/mmbtu[3]
NGL	(6)	Forward NGL price	0.29	2.20	1.33	$/gallon
Power	(146)	Forward power price	43.00	79.20	58.34	$/MWH
Commodity contracts - physical[1]						
Natural gas	(10)	Forward gas price	3.50	5.31	4.39	$/mmbtu[3]
Crude	(16)	Forward crude price	82.85	122.61	99.87	$/barrel
NGL	6	Forward NGL price	0.04	2.39	1.65	$/gallon
Commodity options[2]						
Crude	(5)	Option volatility	14%	18%	16%	
NGL	2	Option volatility	24%	30%	26%	
	(172)					

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

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

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

	Six months ended June 30,	
	2014	2013
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(164)**	(24)
Total gains/(loss)		
Included in earnings[1]	**(18)**	(74)
Included in OCI	**-**	11
Settlements	**10**	8
Level 3 net derivative liability at end of period	**(172)**	(79)

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

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at June 30, 2014 or 2013.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totalled $98 million at June 30, 2014 (December 31, 2013 - $103 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $299 million at June 30, 2014 (December 31, 2013 - $287 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. At June 30, 2014, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2013 - $580 million).

At June 30, 2014, the Company's long-term debt had a carrying value of $29,220 million (December 31, 2013 - $25,168 million) and a fair value of $33,426 million (December 31, 2013 - $27,469 million).

11. INCOME TAXES

The effective income tax rate for the three and six months ended June 30, 2014 were 24.9% and 23.5%, respectively (2013 - 24.6% and 24.8%, respectively).

12. RETIREMENT AND POSTRETIREMENT BENEFITS

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 provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension 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. The Company also provides OPEB, which primarily include supplemental health and dental, health spending account and life insurance coverage, for qualifying retired employees.

NET BENEFIT COSTS RECOGNIZED

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars)				
Benefits earned during the period	**29**	29	**59**	57
Interest cost on projected benefit obligations	**26**	21	**52**	43
Expected return on plan assets	**(32)**	(26)	**(64)**	(52)
Amortization of prior service costs	**1**	-	**1**	1
Amortization of actuarial loss	**7**	13	**14**	26
Net benefit costs on an accrual basis[1,2]	**31**	37	**62**	75

1 *Included in net benefit costs for the three and six months ended June 30, 2014 are costs related to OPEB of $4 million and $8 million (2013 - $5 million and $9 million).*

2 *For the three and six months ended June 30, 2014, offsetting regulatory liabilities of $1 million and $3 million (2013 - $1 million and $2 million regulatory assets) have been recorded to the extent pension and OPEB costs are expected to be refunded to or collected from customers in future rates.*

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Six months ended June 30,	**2014**	2013	**2014**	2013
(millions of Canadian dollars)				
Contributions paid	**64**	64	**5**	6
Contributions expected to be paid in the next six months	**55**		**6**	
Total contributions expected to be paid in the year	**119**		**11**	

13. CONTINGENCIES

ENBRIDGE ENERGY PARTNERS, L.P.

As at June 30, 2014, Enbridge holds an approximate 20.5% combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013 and resubmitted the work plan on April 23, 2013 and again on May 1, 2013 based on EPA comments. The EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modification on May 8, 2013. EEP incorporated the modification and submitted an approved SORA on May 13, 2013. At this time, EEP has completed substantially all of the SORA, with the exception of required dredging in and around Morrow Lake and its delta.

EEP is also working with the Michigan Department of Environmental Quality (MDEQ) to transition submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities from the EPA to the MDEQ, through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at June 30, 2014, EEP's total cost estimate for the Line 6B crude oil release was US$1,157 million ($186 million after-tax attributable to Enbridge), which is an increase of US$35 million ($5 million after-tax attributable to Enbridge) as compared with December 31, 2013 and March 31, 2014. On May 28, 2014, the MDEQ's Water Resource Division approved EEP's Schedule of Work for the remainder of 2014. Approximately US$30 million of the increase in the total cost estimate during the three months ended

June 30, 2014 is primarily related to the finalization of the MDEQ approved Schedule of Work and other costs related to the on-going river restoration activities near Ceresco.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at June 30, 2014. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews throughout the year. On May 1 of each year, the insurance program is up for renewal and includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents excluding costs for fines and penalties.

A majority of the costs incurred in connection with 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. Including EEP's remediation spending through June 30, 2014, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at June 30, 2014, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable. In March 2013, the Company filed a lawsuit against one insurer who is disputing recovery eligibility for Line 6B costs. While the Company believes outstanding claims are covered under the policy, there can be no assurance the Company will prevail in this lawsuit.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2015 with a liability aggregate limit of US$700 million, including sudden and accidental pollution liability. The deductible applicable to oil pollution events was increased to US$30 million per event, from the previous US$10 million. In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 17 actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material.

As at June 30, 2014, included in EEP's estimated costs related to the Line 6B crude oil release is US$30 million in fines and penalties. Due to the absence of sufficient information, EEP cannot provide a reasonable estimate of the liability for potential additional fines and penalties that could be assessed in connection with the Line 6B release. Discussions with governmental agencies regarding fines and penalties are ongoing.

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 LITIGATION

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.

14. SUBSEQUENT EVENTS

ENBRIDGE ENERGY PARTNERS, L.P. EQUITY RESTRUCTURING TRANSACTION

Effective July 1, 2014, Enbridge Energy Company, Inc., a wholly owned subsidiary of Enbridge and the General Partner (GP) of EEP, entered into an equity restructuring transaction in which the Company irrevocably waived its right to receive cash distributions and allocations in excess of 2% in respect of its GP interest in the existing incentive distribution rights in exchange for the issuance of (i) 66.1 million units of a new class of EEP units designated as Class D Units, and (ii) 1,000 units of a new class of EEP units designated as Incentive Distribution Units. The Class D Units entitle the Company to receive quarterly distributions equal to the distribution paid on the EEP's common units. This restructuring decreases the Company's share of incremental cash distributions from 48% of all distributions in excess of US$0.495 per unit per quarter down to 23% of all distributions in excess of EEP's current quarterly distribution of US$0.5435 per unit per quarter. The transaction will apply to all distributions declared subsequent to the effective date.

EQUITY ISSUANCES

On July 8, 2014, the Company issued 1.2 million Common Shares for gross proceeds of approximately $60 million pursuant to the underwriters' over-allotment option of the previously announced common equity offering of 7.9 million Common Shares that closed on June 24, 2014.

On July 17, 2014, the Company issued 14 million Preference Shares, Series 13 for gross proceeds of $350 million.

HIGHLIGHTS

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
(millions of Canadian dollars, except per share amounts)				
Earnings attributable to common shareholders				
Liquids Pipelines	**431**	(67)	**475**	80
Gas Distribution	**19**	27	**155**	134
Gas Pipelines, Processing and Energy Services	**107**	160	**298**	189
Sponsored Investments	**87**	72	**171**	114
Corporate	**112**	(150)	**1**	(225)
Earnings attributable to common shareholders from continuing operations	**756**	42	**1,100**	292
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	-	**46**	-
	756	42	**1,146**	292
Earnings per common share	**0.92**	0.05	**1.39**	0.37
Diluted earnings per common share	**0.91**	0.05	**1.38**	0.36
Adjusted earnings[1]				
Liquids Pipelines	**220**	159	**438**	378
Gas Distribution	**15**	25	**118**	138
Gas Pipelines, Processing and Energy Services	**27**	73	**86**	132
Sponsored Investments	**96**	71	**180**	138
Corporate	**(30)**	(22)	**(2)**	8
	328	306	**820**	794
Adjusted earnings per common share[1]	**0.40**	0.38	**1.00**	1.00
Cash flow data				
Cash provided by operating activities	**812**	937	**1,145**	1,730
Cash used in investing activities	**(2,886)**	(1,949)	**(5,629)**	(3,592)
Cash provided by financing activities	**2,490**	731	**4,955**	1,151
Dividends				
Common share dividends declared	**293**	259	**584**	513
Dividends paid per common share	**0.3500**	0.3150	**0.7000**	0.6300
Shares outstanding *(millions)*				
Weighted average common shares outstanding	**824**	806	**822**	797
Diluted weighted average common shares outstanding	**834**	817	**832**	809
Operating data				
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*				
Canadian Mainline[2]	**1,968**	1,604	**1,936**	1,693
Regional Oil Sands System[3]	**690**	402	**680**	440
Spearhead Pipeline	**196**	184	**190**	175
Gas Distribution - Enbridge Gas Distribution (EGD)				
Volumes *(billions of cubic feet)*	**76**	74	**288**	255
Number of active customers *(thousands)*[4]	**2,071**	2,035	**2,071**	2,035
Heating degree days[5]				
Actual	**493**	491	**2,699**	2,289
Forecast based on normal weather	**461**	495	**2,238**	2,366
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*				
Alliance Pipeline US	**1,662**	1,554	**1,695**	1,593
Vector Pipeline	**1,326**	1,408	**1,553**	1,563
Enbridge Offshore Pipelines	**1,590**	1,351	**1,477**	1,401

1 *Adjusted earnings represent earnings attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors. Adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by GAAP.*

2 *Canadian Mainline includes deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.*

3 *Volumes are for the Athabasca mainline and Waupisoo Pipeline and exclude laterals on the Regional Oil Sands System.*

4 *Number of active customers is the number of natural gas consuming EGD customers at the end of the period.*

5 *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in EGD's franchise area. It is calculated by accumulating, for the fiscal period, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Greater Toronto Area.*

SHAREHOLDER INFORMATION

Registrar and Transfer Agent in Canada
Inquiries regarding the Dividend Reinvestment and Share Purchase Plan, change of address, share transfer, lost certificates, dividends, and duplicate mailings should be directed to:

CST Trust Company
P.O. Box 700
Station B
Montreal, Quebec H3B 3K3
Toll free: (800) 387-0825

Dividend Reinvestment & Share Purchase Plan
Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in common shares, or to make payments to purchase additional shares in, either case free of brokerage or other charges. Share purchase cut-off for the 2014 third quarter optional cash payment to purchase additional shares is August 25, 2014.

Investor Relations
Shareholder inquiries regarding the Company's financial and operating performance should be directed to:

Investor Relations
Enbridge Inc.
3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Toll free: (800) 481-2804
Internet: www.enbridge.com

August 1, 2014

3000, 425 – 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8

Telephone: 403.231.3900
Facsimile: 403.231.3920
Toll free: 800.481.2804

enbridge.com

ENBRIDGE®