ENBRIDGE INC
Form 6-K
May 08, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

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

the Securities Exchange Act of 1934

Dated May 8, 2013

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

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

3000, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrants telephone number, including area code)

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

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

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

Yes	No	**P**

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

Yes	No	**P**

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

Yes No P

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

N/A

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 333-185591 AND 33-77022) AND FORM F-10 (FILE NO. 333-181333) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- Press Release dated May 8, 2013
- Interim Report to Shareholders for the three months ended March 31, 2013.

SIGNATURES

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

ENBRIDGE INC.
(Registrant)

Date:	May 8, 2013	By:	/s/ Alison T. Love
			Alison T. Love
			Vice President & Corporate Secretary

NEWS RELEASE

Enbridge reports first quarter adjusted earnings of $488 million or $0.62 per common share

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars)

- First quarter earnings were $250 million including unrealized non-cash mark-to-market losses
- First quarter adjusted earnings were $488 million or $0.62 per common share
- Enbridge Energy Partners, L.P. increased its cost estimate associated with Line 6B remediation efforts by $175 million ($24 million after-tax attributable to Enbridge)
- Enbridge continued to execute its financing plan with the issuance of $600 million of Common Shares and US$400 million of Cumulative Redeemable Preference Shares
- Enbridge announced a $1.2 billion investment in preferred units of Enbridge Energy Partners, L.P.
- Enbridge secured a $0.3 billion project to provide terminal services for the Surmont Phase 2 project
- Enbridge secured a 50% interest in the 300-megawatt Blackspring Ridge Wind Project with an expected investment of $0.3 billion

- Enbridge agreed to invest $0.2 billion in a project to provide pipeline and terminaling services to the proposed Athabasca Oil Corporation Hangingstone Oil Sands Project

- Senior Vice President of Enterprise Safety and Operational Reliability appointed to provide central coordination of Enbridge s enterprise wide priority on safety and environmental protection

- Enbridge and Energy Transfer Partners, L.P. agreed to principal terms for joint development of a project to provide access to the eastern Gulf Coast refinery market

CALGARY, ALBERTA, May 8, 2013 Enbridge Inc. (TSX:ENB) (NYSE:ENB) Enbridge s businesses performed well in the first quarter, said Al Monaco, President and Chief Executive Officer, Enbridge Inc. (Enbridge or the Company). Although we are pleased to be off to a good start, we expect more moderate growth for the balance of the year and we are maintaining our full year adjusted earnings guidance target range of $1.74 to $1.90 per share. We continue to be on track and on budget with the execution of a record number of commercially secured growth projects which we expect will provide a foundation for growth beyond 2013. This includes ten projects which will have at least an initial phase go into service by the end of this year.

Operations

The Company continued to realize strong results from its core businesses in the first quarter of 2013. Significant operating highlights included strong throughput on the Canadian Mainline as the combination of strong supply from the oil sands and wide crude oil price differentials between Canadian and United States midwest refinery markets increased long-haul barrels on the Enbridge system. Liquids Pipelines earnings for the first three months of the year were further bolstered by contributions from recently sanctioned assets, including the startup of the Wood Buffalo and Woodland pipelines, as well as earnings from the Company s interest in the Seaway Crude Pipeline System (Seaway Pipeline), which commenced preliminary service in May 2012 and was further expanded in January 2013. Energy Services had another strong quarter as wide location and crude grade differentials provided attractive arbitrage opportunities. Enbridge Gas Distribution Inc. (EGD) also contributed to the overall earnings growth quarter-over-quarter; however, due to the quarterly timing of revenues and costs, EGD is expected to deliver full year results that are comparable with the prior year.

Forward-Looking Information and Non-GAAP Measures

This news release contains forward-looking information and references to non-GAAP measures. Significant related assumptions and risk factors, and reconciliations are described under the Forward-Looking Information and Non-GAAP Measures sections of this news release, respectively.

Within Sponsored Investments, the stable performance of the liquids pipelines assets within Enbridge Energy Partners, L.P. (EEP) was offset by a decrease in earnings from its gas gathering and processing businesses which continued to be challenged by the low natural gas and natural gas liquids commodity price environment. In March, EEP received an order from the United States Environmental Protection Agency (EPA) (the Order) requiring additional containment and active recovery of submerged oil relating to the 2010 Line 6B crude oil release. As a result of the Order, EEP recognized an additional accrual of US$175 million ($24 million after-tax attributable to Enbridge) in the first quarter. Contributions from Enbridge Income Fund (the Fund) in the first quarter reflected a full quarter of earnings from renewable energy and crude oil storage assets dropped down to the Fund in late 2012; however, this increase was offset by a small one-time write-off of a regulatory deferral account.

The Company s earnings will continue to reflect, as was the case in the first quarter of 2013, changes in unrealized mark-to-market accounting impacts related to the comprehensive long-term economic hedging program Enbridge has in place to mitigate exposures to interest rate variability and foreign exchange, as well as commodity prices. The Company believes that the hedging program supports the generation of reliable cash flows and dividend growth.

Continued Growth

Addressing crude oil market access challenges continues to be a key driver of Enbridge s growth strategy.

Increasing North American supply is resulting in a shortage of pipeline takeaway capacity to the right markets. We recognized the importance of reducing transportation bottlenecks some time ago, and we ve been working with our customers to find solutions from improving the efficiency of our liquids pipelines systems to a full suite of market access initiatives that will open new or expanded markets as they come into service this year and next, and all of them are expected to be operating by 2016. These projects will add significant value for our customers and our shareholders, said Mr. Monaco.

Since the beginning of the year, Enbridge has continued to add to its already robust portfolio of commercially secured growth projects.

In Liquids Pipelines, Enbridge announced new agreements with regional oil sands shippers for facilities and transportation services. In March, Enbridge agreed to invest $0.2 billion in a project to provide pipeline and terminaling services to the proposed Athabasca Oil Corporation s (AOC) Hangingstone Oil Sands Project (AOC Hangingstone). Enbridge subsequently announced in May, an agreement with ConocoPhillips Canada Resources Corp. and Total E&P Canada Ltd. (the ConocoPhillips Surmont Partnership) to expand existing infrastructure at the Enbridge Cheecham Terminal to accommodate incremental bitumen production from Surmont s Phase 2 expansion.

Enbridge is working collaboratively with Alberta producers to deliver transportation solutions that are innovative and cost-effective, said Mr. Monaco. The reach and flexibility of our existing regional oil sands systems enable us to meet our customers near-term needs as well as offer scalability to accommodate their future growth.

Enbridge, with joint venture partner Enterprise Products Partners, L.P. (Enterprise), also completed the addition of further pump stations on the Seaway Pipeline, increasing that system s available capacity out of the Cushing, Oklahoma hub to up to 400,000 barrels per day (bpd) depending on crude oil slate. Actual throughput experienced in the first quarter of 2013 was curtailed due to third party takeaway constraints. These constraints are expected to be eliminated in the fourth quarter of 2013 when a lateral from the Seaway Jones Creek tankage to the ECHO crude oil terminal (ECHO Terminal) is completed. However, capacity is also expected to be limited by increased nominations of heavy crude oil until the first quarter of 2014 when the Seaway Pipeline twin is expected to come into service.

Enbridge continues to advance initiatives to offer new market access options for producers with an emphasis on adding capacity to reach the best markets, said Mr. Monaco. With the increased capacity on the existing Seaway Pipeline from Cushing to the Western Gulf Coast now in service and serving Houston area refineries, we and our partner, Enterprise are now focused on bringing the Seaway Pipeline twinning into service with another 450,000 bpd of capacity. We are very pleased that this project is running ahead of schedule and is now expected to be available for service in the first quarter of 2014.

We also announced in February 2013 a new project to create the first pipeline transportation option from the mid-continent to the Eastern Gulf Coast market. With our joint venture partner, Energy Transfer Partners, L.P. we are making progress in developing the Eastern Gulf Crude Access Pipeline, a project to reverse and repurpose an existing, underutilized gas pipeline. Capitalizing on existing infrastructure is key to minimizing the industry s footprint and delivering solutions faster and at lower cost than new build.

In January 2013, the Company announced the further expansion of its mainline system, in both Canada and the United States, by an additional 230,000 bpd; providing greater capacity for producers in the face of increasing North American crude oil supply.

The Bakken remains a core focus for Enbridge and the Bakken Expansion Program was completed and placed into service in March 2013, complemented by the commencement of operations at the Berthold Rail facility in North Dakota.

In April 2013, EEP announced plans to construct the Beckville cryogenic natural gas processing plant, which will bring EEP s processing capacity to approximately 820 million cubic feet per day (mmcf/d) in the Cotton Valley and Haynesville shale regions.

Execution is one of our top priorities and maintaining and strengthening this core competency is critical to achieving our growth objectives, said Mr. Monaco. We remain on or ahead of schedule and on or under budget on the majority of our 33 projects currently under development.

Expanding its renewable power platform, Enbridge announced in April the securement of a 50% interest in the development of Blackspring Ridge Wind Project (Blackspring Ridge).

Blackspring Ridge is the largest wind project in Western Canada and will add significant generating capacity to our green energy portfolio, reinforcing our position as Canada s second largest generator of wind power, said Mr. Monaco. The site has an excellent wind resource and access to transmission, with the price of electricity substantially fixed through long-term contracts to be sold into the Alberta power pool. In addition to the strong risk-reward profile of these investments, growing our renewable assets contributes to our ability to meet, and exceed, our Neutral Footprint program commitment to generate a kilowatt of renewable energy for every additional kilowatt of power used in our operations. The acquisition of Blackspring Ridge brings our Enbridge-wide interest in renewable generation to up to 1,600 megawatts.

In May, Enbridge announced it entered into an agreement to invest $1.2 billion in preferred units issued by EEP to reduce the amount of third party financing required by EEP to fund its share of the Company s organic growth program. Concurrent with the issuance, EEP also announced it expects to exercise its option in both the Eastern Access and Lakehead System Mainline Expansion Joint Funding Agreements to reduce its economic interest and associated funding of these respective projects from 40% to 25% by the June 30, 2013 deadline. EEP will retain the option to increase its economic interest back up to 40% in both projects within one year of the final project in-service dates.

This financing arrangement and the existence of the joint funding option will enable EEP to finance its $8.5 billion in growth projects in the most efficient manner with the most amount of flexibility for EEP, benefitting both EEP and Enbridge, said Mr. Monaco.

Enbridge s focus on safety and operational reliability was reinforced in January with the appointment of a new Senior Vice President to provide central coordination of these priorities across the enterprise.

Our number one goal is achieving industry leadership in the reliability and integrity of our pipelines and facilities, and protection of the environment, said Mr. Monaco. Being a leader in these areas enables everything else we do including sustaining the growth of our company into the future.

Enbridge s top three priorities of safety and operational reliability, execution and extending our growth beyond 2016 will continue to drive our decisions and actions over coming years, concluded Mr. Monaco. Our value proposition is strong we re well positioned to expand and to extend into new markets, enabling us to create value for our customers and our shareholders. We have confidence that we ll be able to maintain our industry-leading growth.

FIRST QUARTER 2013 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. We further draw your attention to Note 2, Revision of Prior Period Financial Statements to the Consolidated Financial Statements as at and for the three months ended March 31, 2013 which discusses a non-cash revision to comparative financial statements. The discussion and analysis included herein is based on revised financial results for the three months ended March 31, 2012.

- Earnings attributable to common shareholders decreased from $261 million in the first quarter of 2012 to $250 million in the first quarter of 2013. The Company has delivered significant earnings growth from operations quarter-over-quarter; however, the positive impact of this growth was more than offset by a number of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains or losses. Earnings for the three months ended March 31, 2013 were also negatively impacted by the Order relating to the 2010 Line 6B crude oil release, which resulted in an additional accrual of US$175 million ($24 million after-tax attributable to Enbridge) relating to increased additional work required by the Order. Significant operating highlights for the first quarter of 2013 included strong volumes on several Liquids Pipelines assets and contributions from new assets recently placed into service, including the Seaway Pipeline, as well as strong results from both EGD and Energy Services.

- Enbridge s adjusted earnings for the first quarter of 2013 increased to $488 million from $373 million in the comparative period of 2012. This reflected higher volume throughput and tolls, specifically a higher Canadian Mainline International Joint Tariff Residual Benchmark Toll. Demand for discounted Canadian crude by midwest refiners remained high and drove an increase in long-haul barrels. Higher contracted volumes and new assets placed into service in late 2012 on the Regional Oil Sands System and a full quarter of operations from Enbridge s 50% interest in the Seaway Pipeline, as well as stronger contributions from EGD and Energy Services, also contributed to the adjusted earnings increase. Partially offsetting the adjusted earnings increase were higher preference share dividends related to preference share issuances completed to pre-fund commercially secured growth projects.

- In the first quarter of 2013, the Company amended its policy for certain operations related to recognition of a regulatory asset equal to the cumulative amount of depreciation expense not yet recovered in tolls but required to be recovered in future tolls under the terms of applicable long term shipper contracts and as approved by federal regulatory authorities. The Company s historic accounting treatment was first adopted in 1999. The Company s auditors, PwC LLP (PwC), agreed with this treatment. Accounting guidance found in ASC 980-340 (previously FAS 92) was deemed to be not applicable to the Company s circumstances given the high degree of assurance over collectability of the regulatory asset afforded by the long-term contracts. Management applied its policy consistently from 1999 to 2012.

In April 2013, Management became aware that the predominant view among accounting authorities is now that FAS 92 represents a blanket prohibition on the recognition of such regulatory assets. The Company has prepared its financial statements for the three months ended March 31, 2013 following the method now viewed to be appropriate by Management and its auditors, PwC, and will apply this method going forward. Financial statements for prior periods have been revised to permit comparability on a consistent basis. The new method has no effect on cash flow, past or future, and the revisions to the historical periods are not material.

- On May 8, 2013, Enbridge announced it entered into an agreement to invest $1.2 billion in preferred units issued by EEP. EEP will use the proceeds to finance a portion of its commercially secured growth projects, to repay commercial paper and for general partnership purposes. The preferred units, with a price per unit of $25 (par value), will have a fixed yield of 7.5%, with the rate to be reset every five years. Under the preferred units terms, quarterly cash distributions will not be payable in cash during the first eight quarters and will be added to the redemption value. Quarterly cash distributions will be payable beginning in the ninth quarter and deferred distributions are payable on the fifth anniversary or when redemption of the units takes place. The preferred units will be redeemable at EEP s option on the five-year anniversary of the issuance and every fifth year thereafter, at par and including the deferred distribution. Earlier redemption is permitted under certain events including the ability to redeem the preferred units using the net proceeds from EEP s equity issuances or from the sale of assets and from the issuance of debt, in equal amounts. In the event that the preferred units have not been redeemed in full at the fifth anniversary to the issuance, the deferred distribution will be payable at that time. In addition, on or after June 1, 2016, at Enbridge s sole option, the preferred units can be converted into approximately 43.2 million common units of EEP.

- Also on May 8, 2013, EEP announced it expects to exercise the option to reduce its funding and associated economic interest in both the Eastern Access project and Lakehead System Mainline Expansion project from 40% to 25% by the June 30, 2013 deadline. The projects are co-funded by Enbridge and EEP. EEP retains the option to increase its economic interest held in each of the projects by up to 15% within one year of the respective final in-service dates.

- On May 7, 2013, Enbridge announced it had entered into a terminal services agreement with the ConocoPhillips Surmont Partnership to expand existing infrastructure at Enbridge s existing Cheecham Terminal to accommodate incremental bitumen production from Surmont s Phase 2 expansion. The Company will construct two new 450,000 barrel blend tanks and convert an existing tank from blend to diluent service, install receipt and distribution manifolds to facilitate transfers to the Waupisoo Pipeline and upgrade associated measurement equipment. The expansion is expected to come into service in two phases through the fourth quarter 2014 and first quarter of 2015, at an approximate cost of $0.3 billion.

- On April 30, 2013, EEP announced plans to construct a cryogenic natural gas processing plant near Beckville (Beckville Plant) in Panola County, Texas, at an expected cost of approximately US$0.1 billion. The Beckville Plant will offer incremental processing capacity for existing and future customers in the Cotton Valley shale region where EEP s East Texas system is located. The Beckville Plant has a planned capacity of 150 mmcf/d and construction of the plant and associated facilities is anticipated to begin in late 2013, with an expected in-service date of 2015.

- On April 8, 2013, Enbridge secured a 50% interest in the development of the 300-megawatt Blackspring Ridge project, located 50 kilometres (31 miles) north of Lethbridge, Alberta in Vulcan County. The project will be constructed under a fixed price engineering, procurement and construction contract and is expected to be completed by mid-2014. Renewable Energy Credits generated from Blackspring Ridge are contracted to Pacific Gas and Electric Company under a 20-year purchase agreement. The electricity will be sold into the Alberta power pool with pricing fixed on 75% of production through long-term contracts. The Company s total investment in the project is expected to be approximately $0.3 billion.

- On April 1, 2013, the Fund announced it concluded a settlement (the Settlement) with a group of shippers relating to new tolls on the Westspur System. Pursuant to the Settlement, the tolls on the Westspur System will be fixed and increased annually with reference to a pre-identified inflation index, subject to throughput remaining within a volume band close to volumes recently transported on the Westspur System. The Settlement resulted in an after-tax write-down of approximately $12 million ($4 million after-tax attributable to Enbridge) in the first quarter of 2013 related to a deferred regulatory asset which is not expected to be collected under the terms of the Settlement. At the request of certain shippers who did not execute the Settlement, the National Energy Board has not removed the interim status from the historical tolls and has made the new tolls interim as well. As of May 7, 2013, the Fund continues to work with shippers to resolve this matter.

- On March 21, 2013, Enbridge announced it entered into an agreement with AOC to provide pipeline and terminaling services to the proposed AOC Hangingstone project in Alberta. Subject to finalization of scope, Phase I of the project will involve construction of a new 47-kilometre (29-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. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total of 76,000 bpd. Subject to regulatory and other approvals, the Phase I facilities are expected to be placed into service in 2015 at an estimated cost of approximately $0.2 billion.

- On March 14, 2013, EEP received a letter from the EPA with the Order requiring additional containment and active recovery of submerged oil relating to the July 2010 Line 6B leak in Michigan. EEP estimates it will incur additional costs of approximately US$175 million ($24 million after-tax attributable to Enbridge) for the additional work required by the Order. The estimate is an increase to the total estimated costs of US$820 million ($137 million after-tax attributable to Enbridge) related to the Line 6B leak accrual recognized as at December 31, 2012 and excludes fines and penalties. The actual costs incurred may differ from the foregoing estimate as EEP discusses its work plan with the EPA and other regulatory agencies to assure its work plan complies with their requirements. For the three month period ended March 31, 2013, EEP did not receive any payments for insurance receivable claims.

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- On February 15, 2013, Enbridge announced it entered into an agreement with Energy Transfer Partners, L.P. (Energy Transfer) on the terms for joint development of a project to provide access to the eastern Gulf Coast refinery market from the Patoka, Illinois hub. Subject to Federal Energy Regulatory Commission approval, the project will involve the conversion from natural gas service of certain segments of pipeline that are currently in operation as part of the natural gas system of Trunkline Gas Company, LLC, a wholly owned subsidiary of Energy Transfer and Energy Transfer Equity, L.P. The converted pipeline is expected to have a capacity of up to 420,000 bpd to 660,000 bpd, depending on crude slate and the level of subscriptions received in an open season, and is expected to be in service by early 2015. Enbridge and Energy Transfer would each own a 50% interest in the venture. Enbridge s participation in the venture is subject to a minimum level of commitments being obtained in the open season and on completion of due diligence on the conversion cost. Depending on the level of commitments and finalization of scope and capital cost estimates, Enbridge expects to invest approximately US$1.2 billion to US$1.7 billion.

- On January 11, 2013, Enbridge and its partner Enterprise announced completion of pump station additions and modifications to increase capacity on the Seaway Pipeline available to shippers to approximately 400,000 bpd depending on crude oil slate, an increase from the previous capacity of approximately 150,000 bpd. To date in 2013, actual throughput has been curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek facility to Enterprise s ECHO Terminal in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013. However, capacity is also expected to be limited by increased nominations of heavy crude oil until the Seaway Pipeline twin comes into service in the first quarter of 2014.

- On January 4, 2013, Enbridge announced a further expansion of the Canadian Mainline system between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba, at an estimated cost of $0.4 billion, along with an announcement to further expand the Lakehead System owned by EEP between Neche, North Dakota and Superior, Wisconsin, at an estimated cost of US$0.2 billion. Subject to regulatory approval, the expansion involves the addition of pumping horsepower sufficient to raise the capacity of both the Canadian Mainline and the Lakehead System by another 230,000 bpd. This expansion is expected to be in service in 2015. The announcement was in addition to the Company s May 2012 announcement of a project to raise capacity on the same sections of the Canadian Mainline and the Lakehead System by 120,000 bpd at an approximate cost of $0.2 billion and US$0.2 billion, respectively, with an expected in-service of mid-2014.

- Since the end of 2012, the Company completed the following financing transactions:

- In May 2013, an Enbridge subsidiary secured a US$500 million revolving credit facility, bringing Enbridge s enterprise-wide general purpose credit facilities to $14.4 billion.

- On April 16, 2013, Enbridge completed an offering of 13 million Common Shares for gross proceeds of approximately $600 million.

- On March 27, 2013, Enbridge completed an offering of 16 million Cumulative Redeemable Preference Shares, Series 1, for gross proceeds of US$400 million.

- On March 1, 2013, Enbridge Energy Management, L.L.C. (EEM) completed the issuance of 10.4 million Listed Shares for net proceeds of approximately US$273 million. EEM subsequently used the net proceeds from the offering to invest in an equal number of i-units of EEP.

- On February 26, 2013, Enbridge Income Fund Holdings Inc. (ENF) completed the issuance of 3.8 million common shares for gross proceeds of $96 million. ENF subsequently used the proceeds from the issuance of common shares to subscribe for common units of the Fund.

- In February 2013, EEP increased its 364-day credit facility to $1.1 billion.

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DIVIDEND DECLARATION

On April 23, 2013, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2013 to shareholders of record on May 15, 2013.

Common Shares	$0.31500
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[1]	US$0.18080

1 This is the first dividend declared for Preference Shares, Series 1.

CONFERENCE CALL

Enbridge will hold a conference call on Wednesday, May 8, 2013 at 9:00 a.m. Eastern Time (7:00 a.m. Mountain Time) to discuss the first quarter 2013 results. Analysts, members of the media and other interested parties can access the call toll-free at 1-800-447-0521 from within North America and outside North America at 1-847-413-3238, using the access code of 34629096. The call will be audio webcast live at www.enbridge.com/Q1. A webcast replay and podcast will be available approximately two hours after the conclusion of the event and a transcript will be posted to the website within 24 hours. The replay will be available toll-free at 1-888-843-7419 within North America and outside North America at 1-630-652-3042 (access code 34629096) until May 15, 2013.

The conference call will begin with presentations by the Company s President and Chief Executive Officer and the Chief Financial Officer, followed by a question and answer period for investment analysts. A question and answer period for members of the media will then immediately follow.

Enbridge Inc. is a North American leader in delivering energy and has been included on the Global 100 Most Sustainable Corporations in the World ranking for the past five years. As a transporter of energy, Enbridge operates, in Canada and the U.S., the world s longest crude oil and liquids transportation system. The Company also has a significant and growing involvement in the natural gas gathering transmission and midstream businesses, and an increasing involvement in power transmission. As a distributor of energy, Enbridge owns and operates Canada s largest natural gas distribution company, and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in over 1,600 megawatts of renewable and alternative energy generating capacity and is expanding its interests in wind, solar and geothermal energy. Enbridge employs more than 10,000 people, primarily in Canada and the U.S., and is ranked as one of Canada s Greenest Employers, and one of Canada s Top 100 Employers for 2013. Enbridge is included on the 2012/2013 Dow Jones Sustainability World Index and the Dow Jones Sustainability North American Index. Enbridge s common shares trade on the Toronto and New York stock exchanges under the symbol ENB. For more information, visit www.enbridge.com. None of the information contained in, or connected to, Enbridge s website is incorporated in or otherwise part of this news release.

Forward-Looking Information

Forward-looking information, or forward-looking statements, have been included in this news release 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 , 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 green energy; prices of crude oil, natural gas, NGL and green 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 green 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, 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, 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 news release 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 news release 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 news release 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 of the MD&A for the affected business segments. 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, assess performance of the Company and set the Company s dividend payout target. 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.

NON-GAAP RECONCILIATIONS

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Earnings attributable to common shareholders	**250**	261
Adjusting items:		
Liquids Pipelines		
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss	**72**	(27)
Canadian Mainline - Line 9 tolling adjustment	**-**	(6)
Gas Distribution		
EGD - warmer than normal weather	**6**	24
Gas Pipelines, Processing and Energy Services		
Aux Sable - changes in unrealized derivative fair value gains	**-**	(7)
Energy Services - changes in unrealized derivative fair value loss	**30**	154
Sponsored Investments		
EEP - leak remediation costs	**24**	-
EEP - changes in unrealized derivative fair value loss	**1**	-
EEP - NGL trucking and marketing investigation costs	**-**	1
Corporate		
Noverco - changes in unrealized derivative fair value gains	**(1)**	-
Noverco - equity earnings adjustment	**-**	12
Other Corporate - changes in unrealized derivative fair value (gains)/loss	**105**	(10)
Other Corporate - foreign tax recovery	**(4)**	(29)
Other Corporate - tax rate differences/changes	**5**	-
Adjusted earnings	**488**	373

HIGHLIGHTS

	Three months ended March 31,	
	2013	2012
(unaudited; millions of Canadian dollars, except per share amounts)		
Earnings attributable to common shareholders		
Liquids Pipelines	**147**	183
Gas Distribution	**107**	78
Gas Pipelines, Processing and Energy Services	**29**	(106)
Sponsored Investments	**42**	66
Corporate	**(75)**	40
	250	261
Earnings per common share	**0.32**	0.34
Diluted earnings per common share	**0.31**	0.34
Adjusted earnings[1]		
Liquids Pipelines	**219**	150
Gas Distribution	**113**	102
Gas Pipelines, Processing and Energy Services	**59**	41
Sponsored Investments	**67**	67
Corporate	**30**	13
	488	373
Adjusted earnings per common share	**0.62**	0.49
Cash flow data		
Cash provided by operating activities	**793**	648
Cash used in investing activities	**(1,643)**	(928)
Cash provided by financing activities	**420**	663
Dividends		
Common share dividends declared	**254**	221
Dividends paid per common share	**0.3150**	0.2825
Shares outstanding *(millions)*		
Weighted average common shares outstanding	**789**	757
Diluted weighted average common shares outstanding	**801**	769
Operating data		
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*		
Canadian Mainline[2]	**1,783**	1,687
Regional Oil Sands System[3]	**462**	333
Spearhead Pipeline	**165**	144
Gas Distribution - Enbridge Gas Distribution (EGD)		
Volumes *(billions of cubic feet)*	**181**	161
Number of active customers *(thousands)*[4]	**2,042**	2,001
Heating degree days[5]		
Actual	**1,798**	1,490
Forecast based on normal weather	**1,871**	1,770
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*		
Alliance Pipeline US	**1,632**	1,632
Vector Pipeline	**1,720**	1,754
Enbridge Offshore Pipelines	**1,452**	1,501

1 Earnings attributable to common shareholders and Adjusted earnings, along with corresponding per common share amounts, for the three months ended March 31, 2012 have been revised. See Note 2 to the March 31, 2013 Consolidated Financial Statements.

2 Adjusted earnings represent earnings attributable to common shareholders adjusted for 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.

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

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

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

6 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.

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ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

March 31, 2013

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2013

This Management s Discussion and Analysis (MD&A) dated May 7, 2013 should be read in conjunction with the unaudited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three months ended March 31, 2013, 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 Financial Report for the year ended December 31, 2012. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

In connection with the preparation of the Company s consolidated financial statements for the three months ended March 31, 2013, an error was identified in the manner in which the Company recorded deferred regulatory assets associated with the difference between depreciation expense calculated in accordance with U.S. GAAP and negotiated depreciation rates recovered in transportation tolls for certain of its regulated operations. The error was not material to any of the Company s previously issued consolidated financial statements; however, as discussed in Note 2, Revision of Prior Period Financial Statements to the consolidated financial statements as at and for the three months ended March 31, 2013, prior year comparative financial statements have been revised to correct the effect of this error. This non-cash revision did not impact cash flows for any prior period. The discussion and analysis included herein is based on revised financial results for the three months ended March 31, 2012 or other comparative periods as indicated.

CONSOLIDATED EARNINGS

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**147**	183
Gas Distribution	**107**	78
Gas Pipelines, Processing and Energy Services	**29**	(106)
Sponsored Investments	**42**	66
Corporate	**(75)**	40
Earnings attributable to common shareholders	**250**	261
Earnings per common share	**0.32**	0.34
Diluted earnings per common share	**0.31**	0.34

Earnings attributable to common shareholders were $250 million for the three months ended March 31, 2013, or $0.32 per common share, compared with $261 million, or $0.34 per common share, for the three months ended March 31, 2012. The Company has delivered significant earnings growth from operations quarter-over-quarter as discussed below in *Adjusted Earnings*; however, the positive impact of this growth was reduced by a number of unusual, non-recurring or non-operating factors, the most significant of which are changes in unrealized derivative fair value gains or losses. The Company has a comprehensive long-term economic hedging program to mitigate exposures to interest rate, foreign exchange and commodity 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. In addition to the impact of changes in unrealized derivative fair value gains and losses, earnings for the three months ended March 31, 2013 were also negatively impacted by an increased accrual of

US$175 million ($24 million after-tax attributable to Enbridge) associated with a United States Environmental Protection Agency (EPA) order relating to the Line 6B crude oil release. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Crude Oil Releases.*

Significant operating highlights for the first quarter of 2013 included contributions to earnings from strong volumes on several Liquids Pipelines assets and contributions from new assets recently placed into service, including the Seaway Crude Pipeline System (Seaway Pipeline), as well as improved results from both Enbridge Gas Distribution Inc. (EGD) and Energy Services. Within Sponsored Investments, Enbridge Energy Partners, L.P. s (EEP) natural gas business continued to face pressure in light of the low commodity price environment. Finally, as the Company continued to pre-fund its slate of future growth projects, it experienced an increase in financing costs, primarily in the form of preference share dividends.

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 , b 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 green energy; prices of crude oil, natural gas, NGL and green 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 green 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, 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, 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. 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, assess performance of the Company and set the Company s dividend payout target. 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 March 31,	
	2013	2012
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**219**	150
Gas Distribution	**113**	102
Gas Pipelines, Processing and Energy Services	**59**	41
Sponsored Investments	**67**	67
Corporate	**30**	13
Adjusted earnings	**488**	373
Adjusted earnings per common share	**0.62**	0.49

Adjusted earnings were $488 million, or $0.62 per common share, for the three months ended March 31, 2013 compared with $373 million, or $0.49 per common share, for the three months ended March 31, 2012. The following factors impacted the increase in adjusted earnings.

- Within Liquids Pipelines, adjusted earnings increased quarter-over-quarter due to higher volume throughput and tolls, specifically a higher Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll. Higher volumes arose due to strong supply from Western Canada and the on-going effect of crude oil price differentials whereby demand for discounted Canadian crude by midwest refiners remained high and drove an increase in long-haul barrels on the Enbridge system. Higher contracted volumes and new assets placed into service in late 2012 on the Regional Oil Sands System and a full quarter of operations from Enbridge s 50% interest in the Seaway Pipeline also favourably impacted adjusted earnings for the three months ended March 31, 2013.

- Within Gas Distribution, EGD adjusted earnings were favourably impacted in the quarter by higher revenues due to customer mix, customer growth and higher pipeline optimization revenue, partially offset by higher operating and administrative costs. The higher costs are expected to be a continuing drag on earnings for the balance of the year whereas the favourable revenue factors during the first quarter reflected timing and are expected to largely reverse in future quarters. EGD is operating under a cost of service methodology for 2013 compared with the Incentive Regulation (IR) model followed in 2012. Lower rates from the revised rate setting methodology that became effective October 1, 2012 in Enbridge Gas New Brunswick (EGNB) also partially offset the adjusted earnings increase at EGD.

- Within Gas Pipelines, Processing and Energy Services, adjusted earnings increased due to wide differentials which gave rise to additional and more profitable margin opportunities in Energy Services.

- Within Sponsored Investments, adjusted earnings from EEP reflected higher rates on its major liquids pipeline assets, contributions from new storage terminal assets and higher general partner incentive income. Offsetting these positive impacts were lower volumes on EEP s North Dakota system due to wide crude differentials that make transportation of crude by rail competitive, as well as a decrease in its natural gas business due to continued weakness in natural gas and NGL prices.

- Also within Sponsored Investments, Enbridge Income Fund s (the Fund) first quarter earnings included contributions from crude oil storage and renewable energy assets acquired from Enbridge and its wholly-owned subsidiaries in December 2012. The earnings from these acquired assets were previously presented in Liquids Pipelines and Gas Pipelines, Processing and Energy Services. Earnings were also positively impacted by higher preferred unit distributions received from the Fund. These earnings increases were offset by a small one-time write-off of a regulatory deferral balance. Refer to *Recent Developments Sponsored Investments Enbridge Income Fund Saskatchewan System Shipper Complaint*.

• Within the Corporate segment, increased contributions from the Company s investment in Noverco Inc. (Noverco), lower net Corporate segment finance costs and lower operating and administrative costs were partially offset by higher preference share dividends related to recent preference share issuances completed to pre-fund commercially secured growth projects.

RECENT DEVELOPMENTS

SPONSORED INVESTMENTS ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge Energy Management, L.L.C. Share Issuance

Enbridge s ownership in EEP is held through a combination of direct interest, including a 2% general partnership interest, and indirect interest through Enbridge Energy Management, L.L.C. (EEM). In March 2013, EEM completed the issuance of 10.4 million Listed Shares for net proceeds of approximately US$273 million in which Enbridge did not participate. EEM subsequently used the net proceeds from the offering to invest in an equal number of i-units of EEP. In connection with this issuance, the Company made a capital contribution of $5.8 million to maintain its 2% general partner interest in EEP. EEP will utilize such proceeds to repay commercial paper, to finance a portion of its capital expansion program relating to its core liquids and natural gas systems and for general partnership purposes.

EEP Preferred Unit Private Placement and Joint Funding Option Exercise

In May 2013, Enbridge announced it entered into an agreement to invest $1.2 billion in preferred units issued by EEP to reduce the amount of third party financing required by EEP to fund its share of the Company s organic growth program. Concurrent with the issuance, EEP also announced it expects to exercise its option in both the Eastern Access and Lakehead System Mainline Expansion Joint Funding Agreements to reduce its economic interest and associated funding of these respective projects from 40% to 25% by the June 30, 2013 deadline. EEP will retain the option to increase its economic interest back up to 40% in both projects within one year of the final project in-service dates. For further discussion refer to *Liquidity and Capital Resources*.

Lakehead System Crude Oil Releases

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 of 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.

As at March 31, 2013, and as previously disclosed in March 2013, EEP s total cost estimate for the Line 6B crude oil release was US$995 million ($161 million after-tax attributable to Enbridge) which is an increase of US$175 million ($24 million after-tax attributable to Enbridge) compared with the December 31, 2012 estimate. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the Pipeline and Hazardous Materials Safety Administration (PHMSA) civil penalty of US$3.7 million which was paid in the third quarter of 2012. On March 14, 2013, EEP received an order from the EPA (the Order) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013, resubmitted the work plan on April 23, 2013 and is waiting for a response from the EPA. EEP does not believe these refinements in the work plan will materially change its cost estimate. The Order states the work must be completed by December 31, 2013.

The US$175 million increase in the total cost estimate is attributable to additional work required by the Order. The actual costs incurred may differ from the foregoing estimate as EEP discusses its work plan with the EPA and works with other regulatory agencies to assure its work plan complies with their requirements. Any such incremental costs will not be recovered under EEP s insurance policies as the expected costs for the incident will exceed the limits of its insurance coverage.

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

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. The May 1 insurance renewal programs include commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP s remediation spending through March 31, 2013, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

In the first quarter of 2012, EEP received payments of US$50 million ($7 million after-tax attributable to Enbridge) for insurance receivable claims previously recognized as a reduction to environmental costs in 2011. For the three month period ended March 31, 2013, EEP did not receive any payments for insurance receivable claims. As at March 31, 2013, EEP has recorded total insurance recoveries of US$505 million for the Line 6B crude oil release.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers of the 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 believe their payment is predicated on the outcome of the recovery from that insurer. While EEP believes the claims for the remaining US$145 million are covered under the policy, there can be no assurance that EEP will prevail in this lawsuit. EEP expects to record receivables for additional amounts claimed for recovery pursuant to its insurance policies during the period that EEP deems realization of the claim for recovery to be probable.

Enbridge s current comprehensive insurance program, under which EEP is insured, expired April 30, 2013 and had a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability. Enbridge has renewed its comprehensive property and liability insurance programs effective May 1, 2013 through April 30, 2014. The renewed coverage for the liability program has an aggregate limit of US$685 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 the Enbridge entities on an equitable basis based on an insurance allocation agreement EEP has entered into with Enbridge and another Enbridge subsidiary.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 30 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, EEP does not expect the outcome of these actions to be material. As noted above, on July 2, 2012, PHMSA announced a Notice of Probable Violation related to the Line 6B crude oil release, including a civil penalty of US$3.7 million that EEP paid in the third quarter of 2012. One claim related to the Line 6A crude oil release has been filed against one of EEP s affiliates by the State of Illinois in the Illinois state court. The parties are currently operating under an agreed interim order.

SPONSORED INVESTMENTS ENBRIDGE INCOME FUND

Saskatchewan System Shipper Complaint

Throughout 2011 and 2012, the Fund continued to review the structure of its tolls with shippers following a shipper complaint in early 2011. On April 1, 2013, the Fund announced a settlement (the Settlement) had been concluded relating to new tolls on the Westspur System with a group of shippers. At the request of certain shippers who did not execute the Settlement, the National Energy Board (NEB) has not removed the interim status from historical tolls and has made the new tolls interim as well. As of May 7, 2013, the Fund continues to work with shippers to resolve the matter.

The Settlement establishes a toll methodology for an initial term of five years, with additional one year renewal terms unless otherwise terminated. Pursuant to the Settlement, the tolls on the Westspur System will be fixed and increased annually with reference to a pre-identified inflation index, subject to throughput remaining within a volume band close to volumes recently transported on the Westspur System. The Settlement resulted in the discontinuance of rate-regulated accounting for the Westspur system and the Fund recorded an after-tax write-down of approximately $12 million ($4 million after-tax attributable to Enbridge) in the first quarter of 2013 related to a deferred regulatory asset which is not expected to be collected under the terms of the

Settlement.

CORPORATE

Preference Share Issuance

On March 27, 2013, the Company issued 16 million Preference Shares, Series 1 for gross proceeds of US$400 million. The 4.0% Cumulative Redeemable Preference Shares, Series 1 are entitled to receive a fixed, cumulative, quarterly preferential dividend of US$1.00 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding Preference Shares for US$25.00 per share plus all accrued and unpaid dividends on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 1 will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series 2, subject to certain conditions, on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series 2 will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then three-month United States Government treasury bill rate plus 3.1%.

Common Share Issuance

On April 16, 2013, the Company completed the issuance of 13 million Common Shares for gross proceeds of approximately $600 million. The proceeds will be used to fund recently announced regional oil sands, renewable energy and natural gas pipelines and processing projects, reduce outstanding indebtedness, make investments in subsidiaries and for general corporate purposes.

GROWTH PROJECTS   COMMERCIALLY SECURED PROJECTS

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

(Canadian dollars, unless stated otherwise)		Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
LIQUIDS PIPELINES					
1.	Seaway Crude Pipeline System				
	Acquisition/Reversal/Expansion	US$1.3 billion	US$1.2 billion	2012-2013	Complete
	Twinning/Extension	US$1.1 billion	US$0.2 billion	2014	Pre-construction
2.	Suncor Bitumen Blend	$0.2 billion	$0.1 billion	2013	Substantially complete
3.	Eddystone Rail Project	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
4.	Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.3 billion	2013-2014 (in phases)	Under construction
5.	Eastern Access[3]				
	Toledo Expansion	US$0.2 billion	US$0.1 billion	2013	Complete
	Line 9 Reversal and Expansion	$0.4 billion	No significant expenditures to date	2013-2014 (in phases)	Pre-construction
6.	Norealis Pipeline	$0.5 billion	$0.3 billion	2014	Under construction

7.	Flanagan South Pipeline Project	US$2.8 billion	US$0.3 billion	2014	Pre-construction
8.	Canadian Mainline Expansion	$0.6 billion	No significant expenditures to date	2014-2015 (in phases)	Pre-construction
9.	Athabasca Pipeline Twinning	$1.2 billion	$0.1 billion	2014	Under construction
10.	Surmont Phase 2 Expansion	$0.3 billion	No significant expenditures to date	2014-2015 (in phases)	Pre-construction

		Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
11.	Edmonton to Hardisty Expansion	$1.8 billion	No significant expenditures to date	2015	Pre-construction
12.	Southern Access Extension	US$0.8 billion	US$0.1 billion	2015	Pre-construction
13.	AOC Hangingstone Lateral	$0.2 billion	No significant expenditures to date	2015	Pre-construction
14.	Canadian Mainline System Terminal Flexibility and Connectivity	$0.6 billion	No significant expenditures to date	2013-2015 (in phases)	Pre-construction
GAS DISTRIBUTION					
15.	Greater Toronto Area Project	$0.6 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES					
16.	Massif du Sud Wind Project	$0.2 billion	$0.1 billion	2012-2013	Complete
17.	Lac Alfred Wind Project	$0.3 billion	$0.3 billion	2013 (in phases)	Under construction
18.	Montana-Alberta Tie-Line	US$0.4 billion	US$0.3 billion	2013	Under construction
19.	Cabin Gas Plant	$0.8 billion	$0.7 billion	To be determined	Deferred
20.	Peace River Arch Gas Development	$0.3 billion	$0.1 billion	2012-2014 (in phases)	Under construction
21.	Tioga Lateral Pipeline	US$0.1 billion	US$0.1 billion	2013	Under construction
22.	Venice Condensate Stabilization Facility	US$0.2 billion	US$0.1 billion	2013	Under construction
23.	Blackspring Ridge Wind Project	$0.3 billion	No significant expenditures to date	2014	Pre-construction
24.	Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2014	Under construction
25.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.2 billion	2014	Under construction
26.	Heidelberg Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
SPONSORED INVESTMENTS					
27.	EEP - Bakken Expansion Program	US$0.3 billion	US$0.3 billion	2013	Complete
28.	The Fund - Bakken Expansion Program	$0.2 billion	$0.2 billion	2013	Complete
29.	EEP - Berthold Rail Project	US$0.1 billion	US$0.1 billion	2013	Complete
30.	EEP - Ajax Cryogenic Processing Plant	US$0.2 billion	US$0.2 billion	2013	Substantially complete
31.	EEP - Bakken Access Program	US$0.1 billion	US$0.1 billion	2013	Substantially complete
32.	EEP - Texas Express Pipeline	US$0.4 billion	US$0.2 billion	2013	Under construction
33.	EEP - Line 6B 75-Mile Replacement Program	US$0.3 billion	US$0.3 billion	2013	Under construction
34.	EEP - Eastern Access	US$2.6 billion	US$0.4 billion	2013-2016 (in phases)	Pre-construction

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		Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
35.	EEP - Lakehead System Mainline Expansion	US$2.4 billion	No significant expenditures to date	2014-2016 (in phases)	Pre-construction
36.	EEP - Beckville Cryogenic Processing Facility	US$0.1 billion	No significant expenditures to date	2015	Pre-construction
37.	EEP - Sandpiper Project	US$2.5 billion	No significant expenditures to date	2016	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 project up to March 31, 2013.

3 *See* Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. Eastern Access *for project discussion.*

LIQUIDS PIPELINES

Seaway Crude Pipeline System

Acquisition of Interest

In 2011, Enbridge acquired a 50% interest in the Seaway Pipeline at a cost of approximately US$1.2 billion. Seaway Pipeline includes the 805-kilometre (500-mile), 30-inch diameter long-haul system from Freeport, Texas to Cushing, Oklahoma.

Reversal and Expansion

The flow direction of the Seaway Pipeline was reversed, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. The initial reversal of the pipeline and preliminary service commenced in 2012, providing initial capacity of 150,000 barrels per day (bpd). Further pump station additions and modifications were completed in January 2013, increasing capacity available to shippers to up to approximately 400,000 bpd, depending on crude oil slate. Actual throughput experienced to date in 2013 has been curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek facility to Enterprise Product Partners L.P. s (Enterprise) ECHO crude oil terminal (ECHO Terminal) in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013. However, capacity is also expected to be limited by increased nominations of heavy crude oil until the Seaway Pipeline twin comes into service in the first quarter of 2014, as discussed below.

Twinning and Extension

Based on additional capacity commitments from shippers, a second line will be constructed that is expected to more than double the existing capacity of the Seaway Pipeline to 850,000 bpd in the first quarter of 2014. This 30-inch diameter pipeline will follow the same route as the existing Seaway Pipeline. Included in the project scope is a 105-kilometre (65-mile), 36-inch new-build lateral from the Seaway Jones Creek facility southwest of Houston, Texas into the ECHO Terminal.

In addition, a 137-kilometre (85-mile) pipeline will be constructed from the ECHO Terminal to the Port Arthur/Beaumont, Texas refining center to provide shippers access to the region s heavy oil refining capabilities. This extension will offer capacity of 560,000 bpd and, subject to regulatory approvals, is expected to be available in the first quarter of 2014.

Including the acquisition of the 50% interest in the Seaway Pipeline, Enbridge s total expected cost for the Seaway Pipeline is approximately US$2.4 billion. The acquisition, reversal and expansion are expected to cost US$1.3 billion, with the twinning, extension and lateral to the ECHO Terminal components of the project expected to cost approximately US$1.1 billion. Total expenditures incurred to date are approximately US$1.4 billion.

Suncor Bitumen Blend

Under an agreement with Suncor Energy Oil Sands Limited Partnership (Suncor), the Suncor Bitumen Blend project includes the construction of a new 350,000 barrel tank, new blend and diluent lines and pumping capacity to connect with Suncor s lines just outside Enbridge s Athabasca Tank Farm. Upon completion, which is expected in the second quarter of 2013, the new facilities will enable Suncor to transport blended bitumen volumes from its Firebag production into the Wood Buffalo pipeline. The estimated capital cost of the project is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion.

South Cheecham Rail and Truck Terminal

The Company has partnered with Keyera Corp. to construct the South Cheecham Rail and Truck Terminal (the Terminal), located approximately 75 kilometres (47 miles) southeast of Fort McMurray, Alberta. The Terminal, to be developed in phases, will be a multi-purpose hydrocarbon rail and truck terminal, designed to support bitumen producers within the Athabasca oil sands area and facilitate product in and out. In addition to the facilities for handling diluent and diluted bitumen at the Terminal, the initial phase is planned to include a diluted bitumen pipeline connection to Enbridge s existing Cheecham Terminal. Construction is underway and completion of the first phase is expected to take place in the second quarter of 2013 for a total cost of approximately $90 million. Enbridge s share of the project costs will be based upon its 50% joint venture interest.

Eddystone Rail Project

The Company entered into a joint venture agreement with Canopy Prospecting Inc. to develop 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 will include leasing portions of a power generation facility and reconfiguring 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. Subject to regulatory and other approvals, the project is expected to be placed into service by the end of 2013 to receive and deliver an initial capacity of 80,000 bpd, expandable to 160,000 bpd. The total estimated cost of the project is approximately US$0.1 billion and Enbridge s share of the project costs will be based upon its 75% joint venture interest.

Athabasca Pipeline Capacity Expansion

The Company is undertaking an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including incremental production from the Christina Lake Oil Sands Project operated by Cenovus Energy Inc. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on the mix of crude oil types. The estimated cost of the entire expansion is approximately $0.4 billion, with expenditures to date of approximately $0.3 billion. The initial expansion to 430,000 bpd of capacity was completed and placed into service in March 2013. The remaining additional capacity of 140,000 bpd is expected to be available by early 2014. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

Norealis Pipeline

In order to provide pipeline and terminaling services to the proposed Husky Energy Inc. operated Sunrise Energy Project, the Company is undertaking construction of 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 estimated cost of the project is approximately $0.5 billion, with expenditures to date of approximately $0.3 billion. Although the project is expected to be available for service by the end of 2013, Enbridge expects the pipeline will be placed into service in 2014, concurrent with the start-up of the Sunrise Energy Project.

Flanagan South Pipeline Project

The 950-kilometre (590-mile) Flanagan South Pipeline will have an initial capacity of approximately 585,000 bpd to transport crude oil from the Company s terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline will be installed adjacent to the Company s Spearhead Pipeline for the majority of the route. Subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014. The estimated cost of the project is approximately US$2.8 billion, with expenditures to date of approximately US$0.3 billion.

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Canadian Mainline Expansion

Enbridge is undertaking an estimated $0.2 billion expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project involves the addition of pumping horsepower sufficient to raise the capacity of the Alberta Clipper line by 120,000 bpd to a capacity of 570,000 bpd and is expected to be in service by mid-2014.

In January 2013, Enbridge announced a further expansion of the Canadian Mainline system between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba, at an estimated cost of $0.4 billion, bringing the total expected cost for the expansion to approximately $0.6 billion. Subject to NEB approval, the current scope of the additional expansion involves the addition of pumping horsepower sufficient to raise the capacity of the Alberta Clipper line by another 230,000 bpd to its full capacity of 800,000 bpd. This component of the expansion is expected to be in service in 2015; however, delays in receipt of the applicable regulatory approvals on EEP s portion of the mainline system expansion could affect the target in-service dates of the Canadian Mainline Expansion. See *Growth Projects Commercially Secured Projects Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Mainline Expansion*.

Athabasca Pipeline Twinning

This project involves the twinning of the southern section of the Company s 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, with expenditures to date of approximately of $0.1 billion, will include 345 kilometres (210 miles) of 36-inch pipeline adjacent to the existing Athabasca Pipeline right-of-way. The initial annual capacity of the pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. The line is expected to enter service mid-2014.

Surmont Phase 2 Expansion

In May 2013, the Company announced it had entered into a terminal services agreement with ConocoPhillips Canada Resources Corp. and Total E&P Canada Ltd. (the ConocoPhillips Surmont Partnership) to expand existing infrastructure at the Cheecham Terminal to accommodate incremental bitumen production from Surmont s Phase 2 expansion. The Company will construct two new 450,000 barrel blend tanks and convert an existing tank from blend to diluent service, install receipt and distribution manifolds to facilitate transfers to the Waupisoo Pipeline and upgrade associated measurement equipment. The expansion is expected to come into service in two phases through the fourth quarter of 2014 and first quarter of 2015, at an approximate cost of $0.3 billion.

Edmonton to Hardisty Expansion

The Company is undertaking an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project, with an estimated cost of approximately $1.8 billion, will include 181 kilometres (112 miles) of new 36-inch diameter pipeline, expected to generally follow the same route as Enbridge s existing Line 4 pipeline, and new terminal facilities at Edmonton which include five new 500,000 barrel tanks and connections into existing infrastructure at Hardisty Terminal. The initial capacity of the new line will be approximately 570,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory and other approvals, the project is expected to be placed into service in 2015.

Southern Access Extension

The Southern Access Extension project will consist of the construction of a new 265-kilometre (165-mile), 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois as well as additional tankage and two new pump stations. Subject to regulatory and other approvals, the project is expected to be placed into service in 2015 at an approximate cost of US$0.8 billion, with expenditures to date of approximately US$0.1 billion. The initial capacity of the new line is expected to be approximately 300,000 bpd. While the binding open season that closed in January 2013 did not result in additional capacity commitments from shippers, Enbridge had previously received sufficient capacity commitments from an anchor shipper to support the 24-inch pipeline as proposed.

AOC Hangingstone Lateral

In March 2013, the Company announced that it entered into an agreement with Athabasca Oil Corporation (AOC) to provide pipeline and terminaling services to the proposed AOC Hangingstone Oil Sands Project (AOC Hangingstone) in Alberta. Subject to finalization of scope, Phase I of the project will involve the construction of a new 47-kilometre (29-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. 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. Subject to regulatory and other approvals, the Phase I facilities are expected to be placed into service in 2015 at an estimated cost of approximately $0.2 billion.

Canadian Mainline System Terminal Flexibility and Connectivity

As part of the Light Oil Market Access Program initiative, the Company will undertake 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 cost of the project is expected to be approximately $0.6 billion, with varying completion dates now expected to be between 2013 and 2015 related to existing terminal facility modifications. Such modifications are comprised of upgrading existing booster pumps, additional booster pumps and new tank line connections. This project remains subject to NEB approval.

GAS DISTRIBUTION

Greater Toronto Area Project

EGD plans to expand its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of approximately $0.6 billion, the proposed GTA project will consist of two segments of pipeline and related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. In February 2013, the Company filed an amended application reflecting scope modifications with the Ontario Energy Board (OEB) and, subject to OEB approval, construction is targeted to start in late 2014, with completion expected by the end of 2015.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Massif du Sud Wind Project

Enbridge secured a 50% interest in the 150-megawatt (MW) Massif du Sud Wind Project (Massif du Sud), located 100 kilometres (60 miles) east of Quebec City, Quebec. Project construction was completed in December 2012 and commercial operation commenced in January 2013. Massif du Sud delivers energy to Hydro-Quebec under a 20-year power purchase agreement (PPA). The Company s total investment in the project is expected to be approximately $0.2 billion with expenditures to date of approximately $0.1 billion. Additional post-completion expenditures are expected to be incurred in 2013.

Lac Alfred Wind Project

Enbridge secured a 50% interest in the development of the 300-MW Lac Alfred Wind Project (Lac Alfred), located 400 kilometres (250 miles) northeast of Quebec City in Quebec s Bas-Saint-Laurent region. The project is being constructed under a fixed price, turnkey, engineering, procurement and construction agreement and is being undertaken in two phases. Phase 1, providing 150-MW of generation capacity, was completed and commenced commercial operations in January 2013, with Phase 2, for the remaining 150-MW, expected to be completed late 2013. Lac Alfred is delivering energy to Hydro-Quebec under a 20-year PPA.

The Company s total investment in the project is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.3 billion.

Montana-Alberta Tie-Line

Montana-Alberta Tie-Line (MATL) is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of the growing supply of electric power in Montana and buoyant power demand in Alberta. The total expected cost for both the first 300-MW phase of MATL and the expansion for an additional 300-MW is approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion. The system s north-bound capacity, which is fully contracted, is targeted to be in service in the second quarter of 2013. The expansion of MATL is under active consideration with an in-service date depending on the final scope, regulatory and other approval and customer support.

Cabin Gas Plant

In 2011, the Company secured a 71% interest in the development of the Cabin Gas Plant (Cabin), located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. The Company s total investment in phases 1 and 2 of Cabin was expected to be approximately $1.1 billion. In October 2012, the Company and its partners announced plans to defer both the commissioning of phase 1 and the construction of phase 2. Under the deferral, the Company s total investment in phases 1 and 2 is expected to be approximately $0.8 billion, with expenditures to date of approximately $0.7 billion. Additional expenditures will be incurred throughout 2013 to complete pre-commission construction on Phase 1 and to place Phase 2 into preservation mode. In December 2012, Enbridge started earning fees for its investment made to date in both phases 1 and 2 of Cabin.

Peace River Arch Gas Development

In 2012, the Company acquired from Encana Corporation (Encana) certain sour gas gathering and compression facilities. These facilities, which are either currently in service or under construction, are located in the Peace River Arch (PRA) region of northwest Alberta. The project will be completed in phases with new gathering lines expected to be in service in late 2013 and new NGL handling facilities expected to be completed in first quarter of 2014. Enbridge s investment in the PRA Gas Development is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.1 billion. Enbridge is also working exclusively with Encana on facility scoping for development of additional major midstream facilities in the liquids-rich PRA region. Financial terms of the PRA Gas Development are expected to be substantially consistent with previously established terms of the Cabin development.

Tioga Lateral Pipeline

The United States portion of the Alliance Pipeline (Alliance Pipeline US) is constructing a natural gas pipeline lateral and associated facilities to connect production from the Hess Tioga field processing plant in the Bakken region of North Dakota to the Alliance mainline near Sherwood, North Dakota. The 127-kilometre (79-mile) Tioga Lateral Pipeline will facilitate movement of liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of Alliance. The pipeline will now have an initial design capacity of approximately 126 million cubic feet per day (mmcf/d), which can be expanded based on shipper demand. Through its 50% ownership interest in Alliance Pipeline US, Enbridge s expected cost related to the project is approximately US$0.1 billion, with expenditures to date of approximately US$0.1 billion. In October 2012, Alliance Pipeline US executed a contract with Hess Corporation (Hess) as an anchor shipper. Aux Sable Liquids Products and Hess reached a concurrent agreement for the provision of NGL services. Regulatory approval from the Federal Energy Regulatory Commission (FERC) was received in September 2012 and construction is underway with an expected third quarter 2013 in-service date.

Venice Condensate Stabilization Facility

The Company is carrying out an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility (Venice) at its Venice, Louisiana facility within Enbridge Offshore Pipelines (Offshore). Expenditures to date are approximately US$0.1 billion. The expanded condensate processing capacity is required to accommodate additional natural gas production from the Olympus offshore oil and gas development. Natural gas production from Olympus will move to Enbridge s onshore facility at Venice via Enbridge s Mississippi Canyon offshore pipeline system, where it will be processed to separate and stabilize the condensate. The expansion, which is expected to more than double the capacity of the facility to approximately 12,000 barrels of condensate per day, is expected to be in service in late 2013.

Blackspring Ridge Wind Project

In April 2013, the Company announced that it has secured a 50% interest in the development of the 300-MW Blackspring Ridge Wind Project (Blackspring Ridge), located 50 kilometres (31 miles) north of Lethbridge, Alberta in Vulcan County. The project will be constructed under a fixed price engineering, procurement and construction contract and is expected to be completed by mid-2014. Renewable Energy Credits generated from Blackspring Ridge are contracted to Pacific Gas and Electric Company under a 20-year purchase agreement. The electricity will be sold into the Alberta power pool with pricing fixed on 75% of production through long-term contracts. The Company s total investment in the project is expected to be approximately $0.3 billion.

Big Foot Oil Pipeline

Under agreements with Chevron USA Inc. (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 proposed Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge s undertaking of the Walker Ridge Gas Gathering System (WRGGS) construction, discussed below. Upon completion of the project, Enbridge will operate the Big Foot Oil 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 and an expected in-service date of mid-2014.

Walker Ridge Gas Gathering System

The Company has agreements with 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 WRGGS to provide natural gas gathering services to the proposed 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 mmcf/d. WRGGS is expected to be in service late 2014 and is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.2 billion.

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 (Anadarko), to an existing third-party system. The Heidelberg Lateral Pipeline (Heidelberg), a 20-inch, 55-kilometre (34-mile) pipeline, 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. Subject to regulatory and other approvals, as well as sanctioning of the development by Anadarko and its project co-owners, Heidelberg is expected to be operational by 2016 at an approximate cost of US$0.1 billion.

SPONSORED INVESTMENTS

Bakken Expansion Program

A joint project to further expand crude oil pipeline capacity to accommodate growing crude oil production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba was undertaken by EEP and the Fund. The project, undertaken by EEP in the United States and the Fund in Canada, reversed and expanded an existing pipeline, running from Berthold, North Dakota, to Steelman, Saskatchewan, and constructed a new 16-inch pipeline from a new terminal near Steelman to the Enbridge mainline terminal near Cromer, Manitoba. The project was completed and entered service in March 2013, providing capacity of 145,000 bpd. The United States portion of the project was completed at an approximate cost of US$0.3 billion. Post-completion expenditures will be incurred throughout 2013 on the Canadian side of the project and the estimated capital cost remains at approximately $0.2 billion, with expenditures incurred to date of approximately $0.2 billion.

Enbridge Energy Partners, L.P.

Berthold Rail Project

The Berthold Rail project expanded capacity into the Berthold Terminal by 80,000 bpd and involved the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing infrastructure. The first phase of terminal facilities was completed in 2012, providing additional capacity of 10,000 bpd to the Berthold Terminal. The loading facility and crude oil tankage were subsequently completed and placed into service in March 2013. The total cost of the project was approximately US$0.1 billion.

Ajax Cryogenic Processing Plant

EEP completed the construction of a new natural gas processing plant and related facilities on its Anadarko System in April 2013. The Ajax Plant is expected to enter service in the third quarter of 2013, commensurate with the completion of the Texas Express Pipeline (TEP) discussed below. When operational, the Ajax Plant will provide capacity of 150 mmcf/d and, in conjunction with the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d. The total cost of the project was approximately US$0.2 billion.

Bakken Access Program

The Bakken Access Program represents an upstream expansion that will further complement EEP s Bakken expansion. Upon completion, which is expected in the second quarter of 2013, the Bakken Access Program will enhance crude oil gathering capabilities on the North Dakota System by 100,000 bpd. The program involves increasing pipeline capacity, constructing additional storage tanks and adding truck access facilities at multiple locations in western North Dakota at an approximate cost of US$0.1 billion, with expenditures to date of approximately US$0.1 billion.

Texas Express Pipeline

The TEP is a joint venture to design and construct a new NGL pipeline and two new NGL gathering systems which EEP will build and operate. The NGL pipeline is a joint venture between EEP, Enterprise, Anadarko and DCP Midstream LLC with the NGL gathering systems a joint venture between EEP, Enterprise and Anadarko. EEP will invest approximately US$0.4 billion in the TEP, which will originate in Skellytown, Texas and extend approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. Expenditures to date are approximately US$0.2 billion. TEP is expected to have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. Approximately 250,000 bpd of capacity has been subscribed on the pipeline.

One of the new NGL gathering systems will connect TEP to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma, while the second will connect TEP to the central Texas Barnett Shale processing plants. Subject to regulatory approval, the pipeline and portions of the gathering systems are expected to begin service in the third quarter of 2013.

Line 6B 75-Mile Replacement Program

This program includes 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. Subject to regulatory and other approvals related to two 5-mile segments in Indiana, the new segments are expected to be placed in service in components from the second through fourth quarters of 2013. These costs will be recovered through EEP s tariff surcharge that is part of the system-wide rates for the Lakehead System. The total capital for this replacement program is estimated to be US$0.3 billion, with expenditures to date of approximately US$0.3 billion.

Eastern Access

The Eastern Access initiative includes several Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the United States upper midwest and eastern Canada. The current scope of Enbridge projects includes a reversal of its Line 9 and expansion of the Toledo Pipeline. The current scope of EEP projects includes an expansion of its Line 5 as well as United States mainline system expansions involving the Spearhead North Pipeline (Line 62) and further segments of Line 6B. The individual projects are further described below.

Enbridge plans to reverse a portion of its Line 9A in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at an estimated cost of approximately $48 million. With NEB approval received in July 2012, the Line 9A reversal is expected to be in service in the third quarter of 2013.

Enbridge also plans to undertake 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 is 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 an additional 80,000 bpd of delivery capacity within Ontario and Quebec resulting in the Line 9B capacity expansion which is expected to be completed at an estimated cost of approximately $0.1 billion. Subject to NEB approval, the Line 9B reversal and Line 9B capacity expansion are expected to be available for service in 2014 at a total estimated cost of approximately $0.4 billion.

In May 2013, Enbridge completed an 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. Post-completion expenditures will be incurred throughout 2013 and the estimated cost remains at approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion.

Both the Toledo Pipeline and Line 9 assets are included in the Company s Liquids Pipelines segment.

EEP is expanding its Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario by 50,000 bpd, at a cost of approximately US$0.1 billion. The Line 5 expansion is now targeted to be in service in the second quarter of 2013.

EEP is also undertaking the expansion of its Line 62 between Flanagan, Illinois and Griffith, Indiana by adding horsepower to increase capacity from 130,000 bpd to 235,000 bpd and adding a 330,000 barrel tank at Griffith. Subject to regulatory and other approvals, the Line 62 capacity expansion project is targeted to be placed into service by the end of 2013. EEP also plans to replace additional sections of Line 6B in Indiana and Michigan, including the addition of new pumps and terminal upgrades at Hartsdale, Griffith and Stockbridge, to increase capacity from 240,000 bpd to 500,000 bpd. Portions of the existing 30-inch diameter pipeline will be replaced with 36-inch diameter pipe. Subject to regulatory and other approvals, the target in-service date for this Line 6B project is early 2014. The replacement of the Line 6B sections is in addition to the Line 6B Replacement Program discussed previously. The expected cost of the United States mainline expansions is US$2.2 billion, and includes the US$0.1 billion cost of the previously discussed Line 5 expansion.

The Eastern Access Expansion 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 involve the addition of new pumps, existing station modifications and breakout tankage at the Griffith and Stockbridge terminals. Subject to regulatory and other approvals, the project is expected to be placed into service in 2016 at an estimated capital cost of approximately US$0.4 billion.

The total estimated cost of the United States mainline expansions, including the Line 6B capacity expansion project, is approximately US$2.6 billion, with expenditures to date of approximately US$0.4 billion. The Eastern Access projects are expected to be funded 75% by Enbridge and 25% by EEP, after EEP announced it expects to exercise the option to reduce its funding and associated economic interest in the project by 15% by the June 30, 2013 deadline. 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 15%. For further discussion refer to *Liquidity and Capital Resources*.

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. Included in the expansion are 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 includes a planned increase in capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately

US$0.2 billion. In January 2013, EEP announced a further expansion of the Lakehead System mainline between the border and Superior, to increase capacity from 570,000 bpd to 800,000 bpd, at an estimated capital cost of approximately US$0.2 billion. 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 target in-service dates for the proposed projects are mid-2014 for the initial phase and 2015 for the second phase. Delays in receipt of the applicable regulatory approvals could affect the target in-service dates. Both phases of the Alberta Clipper expansion would require only the addition of pumping horsepower and no pipeline construction.

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 at an estimated capital cost of approximately US$1.3 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. Subject to regulatory and other approvals, the target in-service date for the first phase of the expansion is expected to be in mid-2014. For the second phase of the expansion, which remains subject to finalization of scope and 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 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 122-kilometre (76-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 2015.

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.4 billion and will operate on a cost-of-service basis. The Lakehead System Mainline Expansion is expected to be funded 75% by Enbridge and 25% by EEP, after EEP announced it expects to exercise the option to reduce its funding and associated economic interest in the project by 15% by the June 30, 2013 deadline. Within one year of the final in service date, EEP will have the option to increase its economic interest held at that time by up to 15%. For further discussion refer to *Liquidity and Capital Resources*.

Beckville Cryogenic Processing Facility

In April 2013, EEP announced plans to construct a cryogenic natural gas processing plant near Beckville (Beckville Plant) in Panola County, Texas, at an expected cost of approximately US$0.1 billion. The Beckville Plant will offer incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where EEP s East Texas system is located. The Beckville Plant has a planned capacity of 150 mmcf/d and construction of the plant and associated facilities is anticipated to begin in late 2013, with an expected in-service date of 2015.

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 expansion will involve construction of a 965-kilometre (600-mile) 24-inch diameter line from Beaver Lodge, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, adding 225,000 bpd of capacity on the twin line between Beaver Lodge and Clearbrook and 375,000 bpd of capacity between Clearbrook and Superior.

Sandpiper is expected to cost approximately US$2.5 billion and will be fully funded by EEP. A petition was filed with the FERC to approve recovery of Sandpiper s costs through a surcharge to the Enbridge Pipelines (North Dakota) LLC rates between Beaver Lodge and Clearbrook and a cost of service structure for rates between Clearbrook and Superior. On March 22, 2013, FERC denied the petition on procedural grounds. EEP plans to re-file its petition with modifications to address the FERC s concerns. The pipeline is expected to begin service in early 2016, subject to obtaining regulatory and other approvals, as well as finalization of scope.

GROWTH PROJECTS OTHER PROJECTS UNDER DEVELOPMENT

The following projects are also currently under development by the Company, but have not yet met Enbridge s criteria to be classified as commercially secured.

LIQUIDS PIPELINES

Woodland Pipeline Extension

In 2012, Enbridge received approval from the Alberta Energy Resources Conservation Board to construct the Woodland Pipeline Extension Project. The project will extend the Woodland Pipeline south from Enbridge s Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 385-kilometre (228-mile), 36-inch diameter pipeline, requiring an investment of approximately $1.0 billion to $1.4 billion for an initial capacity of 400,000 bpd, expandable to 800,000 bpd. The estimated investment remains subject to finalization of scope and a definitive cost estimate. All major environmental approvals have been received and, subject to final commercial approval, Enbridge anticipates a 2015 in-service date. Project expenditures to date are approximately $0.1 billion, with pre-development costs being backstopped by shippers pending final commercial approval.

Eastern Gulf Crude Access Pipeline

In February 2013, Enbridge entered into an agreement with Energy Transfer Partners, L.P. (Energy Transfer) on the terms for joint development of a project to provide access to the eastern Gulf Coast refinery market from the Patoka, Illinois hub. Subject to FERC approval, the project will involve the conversion from natural gas service of certain segments of pipeline that are currently in operation as part of the natural gas system of Trunkline Gas Company, LLC, a wholly owned subsidiary of Energy Transfer and Energy Transfer Equity, L.P. The converted pipeline is expected to have a capacity of up to 420,000 bpd to 660,000 bpd, depending on crude slate and the level of subscriptions received in an open season, and is expected to be in service by early 2015. Enbridge and Energy Transfer would each own a 50% interest in the venture. Enbridge s participation in the venture is subject to a minimum level of commitments being obtained in the open season and on completion of due diligence on the conversion cost. Depending on the level of commitments and finalization of scope and capital cost estimates, Enbridge expects to invest approximately US$1.2 billion to US$1.7 billion.

Northern Gateway Project

The 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 import condensate and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

Northern Gateway submitted an application to the NEB in May 2010. The Joint Review Panel (JRP) established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act, has a broad mandate to assess the potential environmental effects of the project and to determine if it is in the public interest. Following sessions with the public, including Aboriginal groups, and the provision of additional information by Northern Gateway, the JRP issued a Hearing Order in May 2011 outlining the procedures to be followed.

In August 2011, Northern Gateway filed commercial agreements with the NEB which provide for committed long-term service and capacity on both the proposed crude oil export and condensate import pipelines. Capacity has also been reserved for use by uncommitted shippers.

In the fall of 2011, Northern Gateway responded to written questions by intervenors and government participants.

In a Procedural Direction issued in December 2011, the JRP indicated community hearings would be scheduled so the JRP would hear all oral evidence from registered intervenors first, followed by oral statements from registered participants. Community hearings for oral evidence and statements took place between January and August 2012 in various communities. A written record of what was said each day in the community hearings is available on the JRP s website. Intervenors responded to questions by Northern Gateway on July 6, 2012. Northern Gateway filed reply evidence to the evidence of the intervenors on July 20, 2012. The reply evidence contained details of further enhancements in pipeline design and operations. These extra measures, estimated to cost an additional $400 million to $500 million, together with additional marine infrastructure, result in a total estimated project cost of approximately $6.6 billion. The enhancements include: increasing pipeline wall thickness of the oil pipeline; additional pipeline wall thickness for water crossings such as major tributaries to the Fraser, Skeena and Kitimat Rivers; increasing the number of remotely-operated isolation valves by 50% within British Columbia to protect high-value fish habitat; increasing frequency of in-line inspection surveys across the entire Northern Gateway pipeline system by a minimum of 50% over and above current standards; installing dual leak detection systems; and staffing pump stations in remote locations on a 24 hour/7 day basis for on-site monitoring, heightened security and rapid response to abnormal conditions.

The final hearings commenced on September 4, 2012 where Northern Gateway, intervenors, government participants and the JRP questioned those who have presented oral or written evidence. In April 2013, the JRP issued their potential conditions if the project were to be approved. The issuance does not indicate an expectation the proposed project will be approved, but permits all parties to provide comments or to suggest additional conditions for the JRP to consider. Northern Gateway is undertaking a review of the conditions; and no unworkable conditions have currently been identified.

Written final argument must be filed by May 31, 2013. Final hearings for oral argument will start on June 17, 2013. Based on this projected schedule, the JRP expects to issue its reports and findings on the proposed project by December 2013.

Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so. 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.

On February 23, 2012, Transport Canada published its TERMPOL Review Process Report of the Northern Gateway s proposed marine operations. Transport Canada has filed the results of the study with the federal JRP tasked with assessing the project. The study reviewed the marine operations associated with the Northern Gateway terminal and associated tanker traffic in Canadian waters. The review concluded that: While there will always be residual risk in any project, after reviewing the proponent s studies and taking into account the proponent s commitments, no regulatory concerns have been identified for the vessels, vessel operations, the proposed routes, navigability, other waterway users and the marine terminal operations associated with vessels supporting the Northern Gateway. The TERMPOL report was prepared and approved by Canadian government authorities including Transport Canada; Environment Canada; Fisheries and Oceans Canada; Canadian Coast Guard; and Pacific Pilotage Authority Canada. The Gitxaala First Nations (Gitxaala) filed a Notice of Judicial Review with the Federal Court of Canada challenging the TERMPOL process on the grounds that there had not been adequate consultation with the Gitxaala with respect to the potential impacts on its Rights and Title resulting from the routine operation of the tankers servicing the Northern Gateway terminal in Kitimat. Following the hearing, the Federal Court of Canada issued a decision rejecting the Gitxaala challenge noting that it was premature for the Court to intervene in the process before it has reached a conclusion. The Federal Court of Canada decision has not been appealed.

Expenditures to date, which relate primarily to the regulatory process, are approximately $0.3 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.

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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 Enbridge also maintains a Northern Gateway website in addition to information available on www.enbridge.com. The full regulatory application submitted to the NEB and the 2010 Enbridge Northern Gateway Community Social Responsibility Report are available on www.northerngateway.ca. ***None of the information contained on, or connected to, the JRP website, the Northern Gateway website or Enbridge s 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 to jointly develop the NEXUS Gas Transmission System (NEXUS), 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 proposed NEXUS project would originate in northeastern Ohio, include approximately 400 kilometres (250 miles) of large diameter pipe, and be capable of transporting one billion cubic feet per day of natural gas. The line would follow existing utility corridors to an interconnect in Michigan and utilize the existing Vector Pipeline (Vector) to reach the Ontario market. Upon completion, Spectra would become a 20% owner in Vector, a joint venture between DTE and Enbridge. The partners continue to monitor Utica shale development progress pending increased interest by producers in accessing the Ohio/Michigan/Ontario market.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Canadian Mainline	**143**	99
Regional Oil Sands System	**41**	27
Southern Lights Pipeline	**12**	9
Seaway Pipeline	**13**	-
Spearhead Pipeline	**9**	11
Feeder Pipelines and Other	**1**	4
Adjusted earnings	**219**	150
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(72)**	27
Canadian Mainline - Line 9 tolling adjustment	**-**	6
Earnings attributable to common shareholders	**147**	183

Canadian Mainline

Canadian Mainline adjusted earnings for the three months ended March 31, 2013 increased from the comparative 2012 period due to a combination of higher volume throughput and higher tolls, specifically a higher quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll. Throughput on Canadian Mainline continued to be favourably impacted by supply from oil sands production in Alberta. This steadily growing supply is priced at levels which displaced other non-Canadian production from the midwest market and drove increased long-haul barrels on Canadian Mainline. Volume redirections and refinery disruptions in non-Enbridge markets during the first quarter also resulted in higher volumes directed towards Enbridge s mainline system. Adjusted earnings for the first quarter of 2013 compared with the first quarter of 2012 also reflected an increase in operating and administrative costs, primarily due to higher employee costs, as well as higher depreciation and interest expense.

Plant turnarounds on both the supply side from shippers and on the demand side from refineries, as well as temporary mainline capacity limitations are expected to curtail further volume growth until late in the year. Due to the high price differentials between Western Canada Sedimentary Basin and West Texas Intermediate crude pricing, rail transportation is becoming more competitive and may divert volumes that would otherwise flow on the Enbridge system. Further, as the Canadian Mainline IJT Residual Benchmark Toll is inversely impacted by the Lakehead System Toll, the increase of the Lakehead System toll from US$1.85 per barrel to US$2.13 per barrel effective April 1, 2013 resulted in a decrease in the Canadian Mainline IJT Residual Benchmark Toll from US$2.09 per barrel to US$1.81 per barrel as at that date.

Supplemental information on Canadian Mainline adjusted earnings for the three months ended March 31, 2013 and 2012 is as follows:

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Revenues	**387**	316
Expenses		
Operating and administrative	**99**	81
Power	**29**	29
Depreciation and amortization	**58**	54
	186	164
	201	152
Other expense	**-**	(3)
Interest expense	**(40)**	(31)
	161	118
Income taxes	**(18)**	(19)
Adjusted earnings	**143**	99
Effective United States to Canadian dollar exchange rate[1]	**0.9995**	0.9600

March 31,	**2013**	2012
(United States dollars per barrel)		
IJT Benchmark Toll[2]	**$3.94**	$3.85
Lakehead System Local Toll[3]	**$1.85**	$2.01
Canadian Mainline IJT Residual Benchmark Toll[4]	**$2.09**	$1.84

1 Inclusive of realized gains or 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, 2012, the IJT benchmark toll increased from US$3.85 to US$3.94.

3 The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective April 1, 2012, this toll decreased from US$2.01 to US$1.76 and, effective July 1, 2012, this toll increased from US$1.76 to US$1.85.

4 The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. Effective April 1, 2012, this toll increased from US$1.84 to US$2.09, with no change effective July 1, 2012. For any shipment, this toll is the difference between the IJT toll for that shipment and the Lakehead System Local Toll for that shipment.

	Three months ended March 31,	
	2013	2012
Throughput volume[1] *(thousand barrels per day (kbpd))*	**1,783**	1,687

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 earnings for the three months ended March 31, 2013 increased primarily as a result of higher contracted volumes on the Athabasca pipeline, higher capital expansion fees on the Waupisoo pipeline and new assets placed into service in late 2012, including the Woodland and Wood Buffalo pipelines. Partially offsetting these earnings increases were higher operating and administrative costs, higher depreciation expense due the commissioning of new assets and a decrease in Hardisty Caverns earnings following the sale to the Fund in the fourth quarter of 2012.

Seaway Pipeline

The reversal of the Seaway Pipeline was completed and preliminary service began in May 2012 and drives the quarter-over-quarter increase in earnings. In January 2013, further pump station additions and modifications were completed, increasing capacity available to shippers to up to 400,000 bpd, depending on crude slate; however, actual throughput experienced in the first quarter of 2013 was curtailed due to constraints on third party takeaway facilities. A lateral from the Seaway Jones Creek tankage to the ECHO Terminal in Houston, Texas should eliminate these constraints when it comes into service, expected in the fourth quarter of 2013.

Seaway Pipeline filed for market-based rates in December 2011. As 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 the Seaway Pipeline has been challenged by several shippers. FERC hearings are on-going and a decision by the FERC is expected in the first quarter of 2014; however, there is no prescribed timeline for action. The committed rates on Seaway Pipeline have been upheld by the FERC for the term of the contracts.

Spearhead Pipeline

Spearhead Pipeline earnings decreased due to lower shipper make-up rights expiring in the first quarter of 2013 compared with the prior period and higher operating expenses, primarily pipeline integrity and power costs. The decrease in earnings was partially offset by incremental revenues associated with higher volumes due to increased demand at Cushing, Oklahoma for further transportation on the Seaway Pipeline to the United States Gulf Coast refining market.

Feeder Pipelines and Other

The earnings decrease in Feeder Pipelines and Other primarily reflected higher business development costs not eligible for capitalization, partially offset by higher volumes and tolls on Olympic and Toledo pipelines.

Liquids Pipelines earnings were impacted by the following adjusting items:

- Canadian Mainline earnings for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to risk manage exposures inherent within the Competitive Toll Settlement, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Canadian Mainline earnings for the first quarter of 2012 included a Line 9 tolling adjustment related to services provided in prior periods.

GAS DISTRIBUTION

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		

Enbridge Gas Distribution Inc. (EGD)	**100**	81
Other Gas Distribution and Storage	**13**	21
Adjusted earnings	**113**	102
EGD - warmer than normal weather	**(6)**	(24)
Earnings attributable to common shareholders	**107**	78

The first quarter of 2013 represented EGD s first quarter of operations under a one year cost of service settlement, following completion of its five year IR term. EGD s adjusted earnings for the first quarter of 2013 increased over the comparative period of 2012, primarily due to higher revenue due to favourable customer mix, customer growth and higher pipeline optimization revenue. Partially offsetting the increase in adjusted earnings were higher operating and administrative costs, notably employee related costs and operational and safety costs. The higher costs are expected to be a continuing drag on earnings for the balance of the year whereas the favourable revenue factors during the first quarter reflected timing and are expected to largely reverse in future quarters.

Other Gas Distribution and Storage earnings decreased as a result of lower rates from the revised rate setting methodology that became effective October 1, 2012 in EGNB.

The Company commenced legal proceedings against the Government of New Brunswick in April 2012. An application to the New Brunswick Court of Queen s Bench to quash the Government s rates and tariffs regulation was commenced in May 2012. The Court of Queen s Bench dismissed the application in August 2012, but the Company appealed this decision to the New Brunswick Court of Appeal. The appeal was heard in February 2013 and the Court of Appeal released its decision on May 3, 2013. EGNB s appeal was successful in part, as the Court of Appeal ruled that the part of the rates and tariffs regulation that imposes rates according to a revenue-to-cost ratio was beyond the regulation-making authority of the New Brunswick Lieutenant Governor-in-Council. The Court of Appeal upheld the portion of the regulation that requires EGNB to charge residential customers the lower of market or cost-based rates. The Company is presently studying the impact of the Court of Appeal s decision. EGNB s application for judicial review of the New Brunswick Energy and Utilities Board s decision regarding EGNB s rates that were to take effect as of October 1, 2012 is also pending with the Court of Appeal and is scheduled to be heard on May 15, 2013. As a result of the Court of Appeal s May 3, 2013 decision, it is possible that this hearing may be adjourned. There is no assurance these actions will be successful or will result in any recovery.

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 March 31,	
	2013	2012
(millions of Canadian dollars)		
Aux Sable	**8**	12
Energy Services	**33**	4
Alliance Pipeline US	**10**	10
Vector Pipeline	**7**	6
Enbridge Offshore Pipelines (Offshore)	**2**	3
Other	**(1)**	6
Adjusted earnings	**59**	41
Aux Sable - changes in unrealized derivative fair value gains	**-**	7
Energy Services - changes in unrealized derivative fair value loss	**(30)**	(154)
Earnings/(loss) attributable to common shareholders	**29**	(106)

Aux Sable adjusted earnings decreased from the prior year primarily due to lower fractionation margins and a resultant decrease in contributions from the upside sharing mechanism in its production sales agreement.

Energy Services operates a physical commodity marketing business which captures 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. Energy Services adjusted earnings increased in the first quarter of 2013 compared to the comparative period of 2012 due to wide differentials which gave rise to additional and more profitable margin opportunities. Earnings from Energy Services are dependent on market conditions, which are not expected to be as favourable during the balance of the year as during the first quarter.

Offshore earnings remained weak as low volumes persisted on the majority of its pipelines due to decreased production in the Gulf of Mexico. Effective May 1, 2013, the Company elected to not renew windstorm (hurricane) coverage on its offshore asset portfolio. The Company expects to reassess the market for windstorm coverage and revisit the possible purchase of coverage in future years.

The decrease in earnings from Other was mainly due to the transfer of renewable energy assets to the Fund in December 2012. The decrease was partially offset by fees earned by the Company s investment in Cabin, for which recognition commenced in December 2012.

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

• Aux Sable earnings for first quarter of 2012 reflected a change in the fair value of unrealized derivative financial instruments related to the Company s forward gas processing risk management position.

• Energy Services earnings for each period reflected changes in unrealized fair value losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory. A gain or loss on such a financial derivative corresponds to a similar but opposite loss or gain on the value of the underlying physical transaction which is expected to be realized in the future when the physical transaction settles. Unlike the change in the value of the financial derivative, the gain or loss on the value of the underlying physical transaction is not recorded for financial statement purposes until the periods in which it is realized.

• The adjusting items for the first quarter of 2013 excluded a one-time realized loss of $58 million incurred to close out derivative contracts used to hedge forecasted Energy Services transactions during 2012 which are no longer probable to occur.

SPONSORED INVESTMENTS

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Enbridge Energy Partners, L.P. (EEP)	**36**	36
Enbridge Energy, Limited Partnership (EELP) - Alberta Clipper US	**8**	10
Enbridge Income Fund (the Fund)	**23**	21
Adjusted earnings	**67**	67
EEP - leak remediation costs	**(24)**	-
EEP - changes in unrealized derivative fair value loss	**(1)**	-
EEP - NGL trucking and marketing investigation costs	**-**	(1)
Earnings attributable to common shareholders	**42**	66

EEP adjusted earnings for the first quarter of 2013 were comparable to the prior period although due to offsetting factors. In the first quarter of 2013, EEP adjusted earnings reflected higher rates on its major liquids pipeline assets, contributions from new storage terminal assets placed into service in the latter part of 2012 and higher general partner incentive income. Offsetting these increases in adjusted earnings were weaker liquids volumes originating on EEP s North Dakota system due to wide crude differentials that make transportation of crude by rail competitive, as well as a decline in earnings from EEP s natural gas business owing to weakness in natural gas and NGL prices. Higher operating and administrative expenses, primarily from an increased workforce and higher depreciation expense associated with new assets, further offset adjusted earnings growth.

Earnings for the Fund for the first quarter of 2013 included earnings from crude oil storage and renewable energy assets acquired from Enbridge and its wholly-owned subsidiaries in December 2012. Offsetting earnings growth from these newly acquired assets was a one-time after-tax charge of $12 million ($4 million after-tax attributable to Enbridge) related to the write-off of a regulatory deferral balance for which recoverability is no longer probable. Refer to *Recent Developments Sponsored Investments Enbridge Income Fund Saskatchewan System Shipper Complaint*. Earnings were also positively impacted by higher preferred unit distributions received from the Fund.

Sponsored Investment earnings were impacted by the following adjusting items:

- Earnings from EEP for the first quarter of 2013 included a charge 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. Lakehead System Crude Oil Releases.*

- Earnings from EEP for the first quarter of 2013 included a change in the unrealized fair value loss on derivative financial instruments.

• Earnings from EEP for the first quarter of 2012 reflected a charge for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.

CORPORATE

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Noverco	**39**	20
Other Corporate	**(9)**	(7)
Adjusted earnings	**30**	13
Noverco - changes in unrealized derivative fair value gains	**1**	-
Noverco - equity earnings adjustment	**-**	(12)
Other Corporate - changes in unrealized derivative fair value gains/(loss)	**(105)**	10
Other Corporate - foreign tax recovery	**4**	29
Other Corporate - tax rate differences/changes	**(5)**	-
Earnings/(loss) attributable to common shareholders	**(75)**	40

Noverco adjusted earnings included contributions from Noverco s underlying gas and power distribution investments and the Company s preferred share investment. Compared with the prior period, in the first quarter of 2013, earnings from Noverco s underlying energy distribution investments were higher due to stronger volumes, a small one-time gain on sale of an investment and contributions from a new power business acquired mid-2012. The newly acquired power business, located in the northeast United States, is subject to seasonality similar to gas distribution investments, earning a greater proportion of its expected annual earnings during the colder first and fourth quarters each year. Additional earnings contributions from Noverco during the balance of the year are expected to be muted in comparison to the first quarter.

Other Corporate adjusted loss remained comparable with the prior period as lower net Corporate segment finance costs and lower operating and administrative costs were offset by higher preference share dividends due to an increase in the number of preference shares outstanding. Since the end of the first quarter of 2012, the Company has issued 90 million preference shares for gross proceeds of $2,271 million to provide capital for the Company s current slate of growth projects. See *Recent Developments Corporate Preference Share Issuance*.

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

• Earnings from Noverco for the first quarter of 2013 included a change in the unrealized fair value of derivative financial instruments.

• Earnings from Noverco for the first quarter of 2012 included an unfavourable equity earnings adjustment related to prior periods.

• Earnings/(loss) for each period included changes in the unrealized fair value gains and losses of derivative financial instruments related to forward foreign exchange risk management positions.

• Earnings/(loss) for each period were impacted by taxes related to a historical foreign investment.

- Earnings/(loss) for the first quarter of 2013 was impacted by tax rate differences.

LIQUIDITY AND CAPITAL RESOURCES

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 also maintains a longer horizon funding plan which considers growth capital needs and identifies potential sources of debt and equity funding alternatives, with the objective of maintaining access to low cost capital.

Several of the Company s growth projects will be undertaken jointly with EEP, with EEP having the option to reduce its funding and associated economic interest in these projects by up to 15% before June 30, 2013. In May 2013, EEP announced it expects to exercise its options to pare down its economic interest in both the Eastern Access and Lakehead System Mainline Expansion projects from 40% to 25% by the June 30, 2013 deadline. EEP retains the option to increase its economic interest back up to 40% in the respective projects within one year of the final project in-service dates.

In May 2013, Enbridge announced it entered into an agreement to invest $1.2 billion in preferred units issued by EEP. EEP will use the proceeds to finance a portion of its commercially secured growth projects, to repay commercial paper and for general partnership purposes. The preferred units, with a price per unit of $25 (par value), will have a fixed yield of 7.5%, with the rate to be reset every five years. Under the preferred units terms, quarterly cash distributions will not be payable in cash during the first eight quarters and will be added to the redemption value. Quarterly cash distributions will be payable beginning in the ninth quarter and deferred distributions are payable on the fifth anniversary or when redemption of the units takes place. The preferred units will be redeemable at EEP s option on the five-year anniversary of the issuance and every fifth year thereafter, at par and including the deferred distribution. Earlier redemption is permitted under certain events including the ability to redeem the preferred units using the net proceeds from EEP s equity issuances or from the sale of assets and from the issuance of debt, in equal amounts. In the event that the preferred units have not been redeemed in full at the fifth anniversary to the issuance, the deferred distribution will be payable at that time. In addition, on or after June 1, 2016, at Enbridge s sole option, the preferred units can be converted into approximately 43.2 million common units of EEP.

In accordance with its funding plan, the Company has been active in the capital markets with the following issuances during 2013:

- Corporate - US$400 million in preference shares; $600 million in common shares;
- EEM - US$273 million in listed shares; and
- Enbridge Income Fund Holdings Inc. - $96 million in common shares, subsequently used to subscribe in common units of the Fund.

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge also has a significant amount of committed bank credit facilities which were further bolstered in 2013. The Company s net available liquidity of $10,832 million at March 31, 2013 was inclusive of approximately $947 million of unrestricted cash and cash equivalents, net of bank indebtedness. In addition to ensuring adequate liquidity, the Company actively manages its bank funding sources to optimize pricing and other terms. The following table provides details of the Company s credit facilities at March 31, 2013 and December 31, 2012.

		March 31, 2013			December 31, 2012
	Maturity Dates[2]	Total Facilities	Draws[3]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2014	**300**	**26**	**274**	300
Gas Distribution	2014	**712**	**458**	**254**	712
Sponsored Investments	2014-2017	**3,648**	**1,565**	**2,083**	3,162
Corporate	2014-2017	**9,248**	**1,974**	**7,274**	9,108
		13,908	**4,023**	**9,885**	13,282
Southern Lights project financing[1]	2014	**1,516**	**1,452**	**64**	1,484

Total credit facilities	**15,424**	**5,475**	**9,949**	14,766

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

2 Total facilities include $35 million in demand facilities with no maturity date.

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

In May, an Enbridge subsidiary secured a US$500 million revolving credit facility, bringing Enbridge s enterprise-wide general purpose credit facilities to $14.4 billion.

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 $21 million for specific shipper commitments.

OPERATING ACTIVITIES

Cash provided by operating activities was $793 million for the three months ended March 31, 2013 compared with $648 million for the three months ended March 31, 2012. The increase in cash provided by operating activities for the first quarter primarily resulted from higher volume throughput and tolls on Canadian Mainline, higher contracted volumes and contributions from new assets recently placed into service within Regional Oil Sands System and stronger contributions from EGD and Energy Services. The favourable operating performance was partially offset by an unfavourable variance in changes in operating assets and liabilities of $171 million (2012 - $268 million). Working capital fluctuated due to the variations in commodity prices and sales volumes within Energy Services, as well as weather-related variations in customer receivable balances, natural gas inventory and borrowing levels at EGD and general changes in activity levels within the Company s businesses.

INVESTING ACTIVITIES

Cash used in investing activities for the three months ended March 31, 2013 was $1,643 million compared with $928 million for the three months ended March 31, 2012. Cash used in investing activities for the three months ended March 31, 2013 included $1,457 million (2012 - $816 million) of additions to property, plant and equipment, primarily directed to the construction of the Company s growth projects. Additionally, greater intangible asset additions of $51 million (2012 - $48 million), primarily software, and additional funding of various investments and joint ventures of $128 million (2012 - $53 million), primarily TEP and Seaway Pipeline, also contributed to the increased cash usage for 2013.

FINANCING ACTIVITIES

Cash generated from financing activities was $420 million for the three months ended March 31, 2013 compared with $663 million for the three months ended March 31, 2012. The quarter-over-quarter decrease in cash provided by financing activities was primarily due to lower issuance of preference shares as well as lower net borrowings. The Company raised net proceeds of $399 million from the issuance of preference shares in the first quarter of 2013 as compared to $826 million for the comparative period. In the first quarter of 2013, the Company s overall debt decreased by $33 million compared to a net increase of $103 in the first quarter of 2012. These decreases were partly offset by contributions, net of distributions, received from third party investors in EEP of $161 million (2012 - $100 million net distributions) and from the Fund s public unitholders of $73 million (2012 - $12 million net distributions).

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 March 31, 2013, dividends declared were $254 million (2012 - $221 million), of which $164 million (2012 - $156 million) were paid in cash and reflected in financing activities. The remaining $90 million (2012 - $65 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 months ended March 31, 2013, 35.4% (2012 - 29.4%) of total dividends declared were reinvested.

On April 23, 2013, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2013 to shareholders of record on May 15, 2013.

Common Shares	$0.31500
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 11	US$0.18080

1 This first dividend declared for the Preference Shares, Series 1 includes accrued dividends from March 27, 2013, the date the shares were issued. The regular quarterly dividend of US$0.25 per share will take effect on September 1, 2013. See Recent Developments Corporate Preference Share Issuance*.*

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE 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 price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

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

Foreign Exchange Risk

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

Interest Rate Risk

The Company s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2017 with an average swap rate of 2.2%.

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 2016. A total of $10,547 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.5%.

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

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and 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 March 31,	
	2013	2012
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**14**	19
Interest rate contracts	**79**	180
Commodity contracts	**-**	(8)
Other contracts	**2**	(1)
Net investment hedges		
Foreign exchange contracts	**(22)**	3
	73	193
Amount of (gains)/loss reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Interest rate contracts[2]	**13**	14
Commodity contracts[3]	**-**	2
	13	16
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**38**	-
Commodity contracts[3]	**(1)**	(2)
	37	(2)
Amount of gains/(loss) from non-qualifying derivatives included in earnings		
Foreign exchange contracts[1]	**(193)**	15
Interest rate contracts[2]	**(4)**	(2)
Commodity contracts[3]	**(53)**	(203)
Other contracts[4]	**6**	-
	(244)	(190)

1 Reported within Transportation and other services revenues and Other Income in the Consolidated Statements of Earnings.

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

3 Reported within Transportation and other services revenue, 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 the Company will not be able to meet its financial obligations, including commitments, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper 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 one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at March 31, 2013. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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 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 these 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

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. Since then, the NEB has issued revised base case assumptions based on feedback from member companies. Companies have 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., Enbridge Pipelines (Westspur) Inc. and Vector Pipelines Limited Partnership (Group 2 companies). In the fourth quarter of 2012, the NEB held a hearing on the abandonment costs estimates for Group 1 companies, and the NEB issued its decision on February 14, 2013 and 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 trust as the appropriate set-aside mechanism to hold pipeline abandonment funds. On May 31, 2013, the Group 1 companies will file the collection mechanism applications and the Group 2 companies will file their set-aside and collection mechanism applications. Once the collection mechanism is approved by the Board, both Group 1 and Group 2 companies can start to recover these costs from shippers through tolls in accordance with 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 specific toll impacts are uncertain at this time as the Company anticipates the NEB filings in mid-2013 will go to hearing prior to NEB approval.

Currently, for certain 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 asset retirement obligation (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.

CHANGES IN ACCOUNTING POLICIES

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As a Securities and Exchange Commission registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

BALANCE SHEET OFFSETTING

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

ACCUMULATED OTHER COMPREHENSIVE INCOME

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

FUTURE ACCOUNTING POLICY CHANGES

Obligations Resulting from Joint and Several Liability Arrangements

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

Parent s Accounting for the Cumulative Translation Adjustment

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

QUARTERLY FINANCIAL INFORMATION

	2013	2012[1]				2011[1]		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
(millions of Canadian dollars, except per share amounts)								
Revenues	**8,017**	7,172	5,786	5,716	6,625	7,308	6,275	6,935
Earnings attributable to common shareholders	**250**	146	187	8	261	155	(10)	297
Earnings per common share	**0.32**	0.19	0.24	0.01	0.34	0.21	(0.01)	0.39
Diluted earnings per common share	**0.31**	0.18	0.24	0.01	0.34	0.20	(0.01)	0.39
Dividends per common share	**0.3150**	0.2825	0.2825	0.2825	0.2825	0.2450	0.2450	0.2450
EGD - warmer/(colder) than normal weather	**6**	(1)	-	-	24	12	-	(2)
Changes in unrealized derivative fair value and intercompany foreign exchange (gains)/loss	**207**	81	93	252	110	(241)	242	(18)

1 Revenues, Earnings attributable to common shareholders, Earnings per common share and Diluted earnings per common share for the 2012 and 2011 comparative periods have been revised. See Note 2 to the March 31, 2013 Consolidated Financial Statements.

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. Gas Distribution s earnings for the fourth quarter of 2011 included an extraordinary charge totaling $262 million, after-tax, as a result of the discontinuance of rate-regulated accounting at EGNB and the related write-off of a deferred regulatory asset and certain capitalized operating costs.

The Company actively manages its exposure to market price 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:

- Reflected in earnings is the Company s share of leak remediation costs and lost revenue associated with the Lines 6A, 6B and Line 14 crude oil releases. For the first quarter of 2013, accruals for remediation costs relating to the Order for Line 6B crude oil release increased by $24 million. For the second, third and fourth quarter of 2012, the amounts related to remediation costs and lost revenue were $2 million, $7 million and $nil (2011 - $6 million, $21 million and $6 million), respectively. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $24 million in the third quarter of 2012 and $3 million, $13 million and $29 million in the second, third and fourth quarters of 2011, respectively.

- In the fourth quarter of 2012, the Company recorded 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. Also included in the fourth quarter of 2012 was a $63 million, after-tax gain on recognition of a regulatory asset related to other postretirement benefits within EGD.

- Fourth quarter earnings for 2012 and 2011 were also impacted by the impact of asset transfers between entities under common control of Enbridge, resulting in income taxes of $56 million and $98 million, respectively, incurred on the related capital gains.

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 March 31,	
	2013	2012
(millions of Canadian dollars)		
Earnings attributable to common shareholders	**250**	261
Adjusting items:		
Liquids Pipelines		
Canadian Mainline - changes in unrealized derivative fair value (gains)/loss	**72**	(27)
Canadian Mainline - Line 9 tolling adjustment	**-**	(6)
Gas Distribution		
EGD - warmer than normal weather	**6**	24
Gas Pipelines, Processing and Energy Services		
Aux Sable - changes in unrealized derivative fair value gains	**-**	(7)
Energy Services - changes in unrealized derivative fair value loss	**30**	154
Sponsored Investments		
EEP - leak remediation costs	**24**	-
EEP - changes in unrealized derivative fair value loss	**1**	-
EEP - NGL trucking and marketing investigation costs	**-**	1
Corporate		
Noverco - changes in unrealized derivative fair value gains	**(1)**	-
Noverco - equity earnings adjustment	**-**	12
Other Corporate - changes in unrealized derivative fair value (gains)/loss	**105**	(10)
Other Corporate - foreign tax recovery	**(4)**	(29)
Other Corporate - tax rate differences/changes	**5**	-
Adjusted earnings	**488**	373

OUTSTANDING SHARE DATA[1]

	Number
Preference Shares, Series A[2]	5,000,000
Preference Shares, Series B[2,3]	20,000,000
Preference Shares, Series D[2,4]	18,000,000
Preference Shares, Series F[2,5]	20,000,000
Preference Shares, Series H[2,6]	14,000,000
Preference Shares, Series J[2,7]	8,000,000
Preference Shares, Series L[2,8]	16,000,000
Preference Shares, Series N[2,9]	18,000,000
Preference Shares, Series P[2,10]	16,000,000
Preference Shares, Series R[2,11]	16,000,000
Preference Shares, Series 1[2,12]	16,000,000
Common Shares - issued and outstanding (voting equity shares)	823,004,148
Stock Options - issued and outstanding (18,116,979 vested)	36,278,922

1 Outstanding share data information is provided as at April 26, 2013.

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 On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series B will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series B into an equal number of Cumulative Redeemable Preference Shares, Series C.

4 On March 1, 2018, and on March 1 every five years thereafter, the holders of Preference Shares, Series D will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series D into an equal number of Cumulative Redeemable Preference Shares, Series E.

5 On June 1, 2018, and on June 1 every five years thereafter, the holders of Preference Shares, Series F will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series F into an equal number of Cumulative Redeemable Preference Shares, Series G.

6 On September 1, 2018, and on September 1 every five years thereafter, the holders of Preference Shares, Series H will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series H into an equal number of Cumulative Redeemable Preference Shares, Series I.

7 On June 1, 2017, and on June 1 every five years thereafter, the holders of Preference Shares, Series J will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series J into an equal number of Cumulative Redeemable Preference Shares, Series K.

8 On September 1, 2017, and on September 1 every five years thereafter, the holders of Preference Shares, Series L will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series L into an equal number of Cumulative Redeemable Preference Shares, Series M.

9 On December 1, 2018, and on December 1 every five years thereafter, the holders of Preference Shares, Series N will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series N into an equal number of Cumulative Redeemable Preference Shares, Series O.

10 On March 1, 2019, and on March 1 every five years thereafter, the holders of Preference Shares, Series P will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series P into an equal number of Cumulative Redeemable Preference Shares, Series Q.

11 On June 1, 2019 and on June 1 every five years thereafter, the holders of Preference Shares, Series R will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series R into an equal number of Cumulative Redeemable Preference Shares, Series S.

12 On June 1, 2018 and on June 1 every five years thereafter, the holders of Preference Shares, Series 1 will have the right to elect to convert (subject to certain provisions) any or all of their Preference Shares, Series 1 into an equal number of Cumulative Redeemable Preference Shares, Series 2.

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

March 31, 2013

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended March 31,	
	2013	2012
(unaudited; millions of Canadian dollars, except per share amounts)		
Revenues		
Commodity sales	**5,924**	4,838
Gas distribution sales	**891**	767
Transportation and other services	**1,202**	1,020
	8,017	6,625
Expenses		
Commodity costs	**5,732**	4,661
Gas distribution costs	**666**	559
Operating and administrative	**664**	632
Depreciation and amortization	**322**	300
Environmental costs, net of recoveries *(Note 11)*	**183**	3
	7,567	6,155
	450	470
Income from equity investments	**101**	46
Other income/(expense)	**(48)**	86
Interest expense	**(255)**	(217)
	248	385
Income taxes *(Note 9)*	**(62)**	(29)
Earnings	**186**	356
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**103**	(80)
Earnings attributable to Enbridge Inc.	**289**	276
Preference share dividends	**(39)**	(15)
Earnings attributable to Enbridge Inc. common shareholders	**250**	261
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.32**	0.34
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.31**	0.34

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2013	2012
(unaudited; millions of Canadian dollars)		
Earnings	**186**	356
Other comprehensive income/(loss), net of tax		
Change in unrealized gains on cash flow hedges	**77**	160
Change in unrealized gains/(loss) on net investment hedges	**(24)**	9
Other comprehensive income/(loss) from equity investees	**2**	(5)
Reclassification to earnings of realized cash flow hedges	**10**	13
Reclassification to earnings of unrealized cash flow hedges	**28**	2
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**9**	6
Change in foreign currency translation adjustment	**187**	(128)
Other comprehensive income	**289**	57
Comprehensive income	**475**	413
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**18**	(56)
Comprehensive income attributable to Enbridge Inc.	**493**	357
Preference share dividends	**(39)**	(15)
Comprehensive income attributable to Enbridge Inc. common shareholders	**454**	342

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(unaudited; millions of Canadian dollars, except per share amounts)	Three months ended March 31, 2013	2012
Preference shares *(Note 6)*		
Balance at beginning of period	**3,707**	1,056
Preference shares issued	**402**	832
Balance at end of period	**4,109**	1,888
Common shares		
Balance at beginning of period	**4,732**	3,969
Dividend reinvestment and share purchase plan	**90**	65
Shares issued on exercise of stock options	**32**	23
Balance at end of period	**4,854**	4,057
Additional paid-in capital		
Balance at beginning of period	**522**	242
Stock-based compensation	**14**	12
Options exercised	**(10)**	(4)
Issuance of treasury stock	**-**	204
Dilution gains and other	**5**	6
Balance at end of period	**531**	460
Retained earnings		
Balance at beginning of period	**3,173**	3,642
Earnings attributable to Enbridge Inc.	**289**	276
Preference share dividends	**(39)**	(15)
Common share dividends declared	**(254)**	(221)
Dividends paid to reciprocal shareholder	**7**	5
Redemption value adjustment attributable to redeemable noncontrolling interests	**(83)**	(51)
Balance at end of period	**3,093**	3,636
Accumulated other comprehensive loss *(Note 7)*		
Balance at beginning of period	**(1,762)**	(1,496)
Other comprehensive income attributable to Enbridge Inc. common shareholders	**204**	81
Balance at end of period	**(1,558)**	(1,415)
Reciprocal shareholding		
Balance at beginning of period	**(126)**	(187)
Issuance of treasury stock	**-**	61
Balance at end of period	**(126)**	(126)
Total Enbridge Inc. shareholders equity	**10,903**	8,500
Noncontrolling interests		
Balance at beginning of period	**3,258**	3,141
Earnings/(loss) attributable to noncontrolling interests	**(92)**	78
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gains on cash flow hedges	**19**	18
Change in foreign currency translation adjustment	**60**	(54)
Reclassification to earnings of realized cash flow hedges	**5**	11
Reclassification to earnings of unrealized cash flow hedges	**-**	1
	84	(24)
Comprehensive income/(loss) attributable to noncontrolling interests	**(8)**	54
Contributions	**275**	2
Distributions	**(114)**	(102)
Other	**7**	(8)
Balance at end of period	**3,418**	3,087
Total equity	**14,321**	11,587

Dividends paid per common share	**0.3150**	0.2825

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
	2013	2012
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**186**	356
Depreciation and amortization	**322**	300
Changes in unrealized loss on derivative instruments	**248**	201
Cash distributions in excess of/(less than) equity earnings	**(31)**	50
Deferred income taxes (recovery)/expense	**1**	(24)
Other	**65**	20
Changes in regulatory assets and liabilities	**12**	15
Changes in environmental liabilities, net of recoveries *(Note 11)*	**161**	(2)
Changes in operating assets and liabilities	**(171)**	(268)
	793	648
Investing activities		
Additions to property, plant and equipment	**(1,457)**	(816)
Long-term investments	**(128)**	(53)
Additions to intangible assets	**(51)**	(48)
Acquisition	**-**	(7)
Affiliate loans, net	**2**	2
Changes in restricted cash	**(9)**	(6)
	(1,643)	(928)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**(212)**	(172)
Net change in commercial paper and credit facility draws	**379**	(220)
Net change in Southern Lights project financing	**-**	(5)
Debenture and term note issues	**-**	500
Debenture and term note repayments	**(200)**	-
Contributions from noncontrolling interests	**275**	2
Distributions to noncontrolling interests	**(114)**	(102)
Contributions from redeemable noncontrolling interests	**91**	-
Distributions to redeemable noncontrolling interests	**(18)**	(12)
Preference shares issued	**399**	826
Common shares issued	**22**	17
Preference share dividends	**(38)**	(15)
Common share dividends	**(164)**	(156)
	420	663
Effect of translation of foreign denominated cash and cash equivalents	**-**	(12)
Increase/(decrease) in cash and cash equivalents	**(430)**	371
Cash and cash equivalents at beginning of period	**1,776**	723
Cash and cash equivalents at end of period	**1,346**	1,094

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited; millions of Canadian dollars; number of shares in millions)	**March 31, 2013**	December 31, 2012
Assets		
Current assets		
Cash and cash equivalents	**1,346**	1,776
Restricted cash	**28**	19
Accounts receivable and other	**4,548**	4,014
Accounts receivable from affiliates	**12**	12
Inventory	**698**	779
	6,632	6,600
Property, plant and equipment, net	**34,955**	33,318
Long-term investments	**3,395**	3,175
Deferred amounts and other assets	**2,424**	2,461
Intangible assets, net	**867**	817
Goodwill	**427**	419
Deferred income taxes	**7**	10
	48,707	46,800
Liabilities and equity		
Current liabilities		
Bank indebtedness	**399**	479
Short-term borrowings	**451**	583
Accounts payable and other	**5,471**	5,052
Interest payable	**228**	196
Environmental liabilities	**254**	107
Current maturities of long-term debt	**656**	652
	7,459	7,069
Long-term debt	**20,549**	20,203
Other long-term liabilities	**2,669**	2,541
Deferred income taxes	**2,562**	2,483
	33,239	32,296
Contingencies *(Note 11)*		
Redeemable noncontrolling interests	**1,147**	1,000
Equity		
Share capital		
Preference shares *(Note 6)*	**4,109**	3,707
Common shares (810 and 805 outstanding at March 31, 2013 and December 31, 2012, respectively)	**4,854**	4,732
Additional paid-in capital	**531**	522
Retained earnings	**3,093**	3,173
Accumulated other comprehensive loss *(Note 7)*	**(1,558)**	(1,762)
Reciprocal shareholding	**(126)**	(126)
Total Enbridge Inc. shareholders equity	**10,903**	10,246
Noncontrolling interests	**3,418**	3,258
	14,321	13,504
	48,707	46,800

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE 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, 2012. 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 March 31, 2013 and results of operations and cash flows for the three month periods ended March 31, 2013 and 2012. 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, 2012, except for the changes in accounting policies *(Note 3)*. 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. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In connection with the preparation of the Company s consolidated financial statements for the three months ended March 31, 2013, an error was identified in the manner in which the Company recorded deferred regulatory assets associated with the difference between depreciation expense calculated in accordance with U.S. GAAP and negotiated depreciation rates recovered in transportation tolls for certain of its regulated operations. Further, to the extent the deferred regulatory asset gave rise to temporary differences, an offsetting regulatory asset with respect to deferred income taxes was also recognized. In accordance with accounting guidance found in Accounting Standards Codification (ASC) 250-10 (SEC Staff Accounting Bulletin No. 99, *Materiality*), the Company assessed the materiality of the error and concluded that it was not material to any of our previously issued consolidated financial statements. In accordance with guidance found in ASC 250-10 (SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*), the Company will revise its comparative consolidated financial statements to correct the effect of this matter. This non-cash revision does not impact cash flows for any prior period.

The following tables present the effect of this correction on individual line items within the Company s Consolidated Statements of Earnings and Consolidated Statements of Financial Position. The effects which flow through to the individual line items of Earnings, Depreciation and amortization, Cash distributions in excess of equity earnings, Deferred income taxes, Changes in regulatory assets and liabilities and Changes in operating assets and liabilities of the Consolidated Statements of Cash Flows are not significant and have no net effect on the Company s cash flows from operating activities.

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(unaudited; millions of Canadian dollars, except per share amounts)	Three months ended March 31, 2012 As Previously Reported	Adjustment	As Revised	Three months ended March 31, 2011 As Previously Reported	Adjustment	As Revised
Transportation and other services revenues	1,022	(2)	1,020	1,039	(2)	1,037
Depreciation and amortization	290	10	300	277	11	288
Income from equity investments	38	8	46	55	6	61
Income taxes expense	(30)	1	(29)	(103)	2	(101)
Earnings	359	(3)	356	433	(5)	428
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(80)	-	(80)	(67)	-	(67)
Earnings attributable to Enbridge Inc.	279	(3)	276	366	(5)	361
Earnings attributable to Enbridge Inc. common shareholders	264	(3)	261	364	(5)	359
Earnings per common share attributable to Enbridge Inc. common shareholders	0.35	(0.01)	0.34	0.49	(0.01)	0.48
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.34	-	0.34	0.48	(0.01)	0.47

(unaudited; millions of Canadian dollars, except per share amounts)	Three months ended June 30, 2012 As Previously Reported	Adjustment	As Revised	Three months ended June 30, 2011 As Previously Reported	Adjustment	As Revised
Transportation and other services revenues	886	(2)	884	1,063	(3)	1,060
Depreciation and amortization	300	10	310	274	10	284
Income from equity investments	34	9	43	54	6	60
Income taxes recovery/(expense)	18	-	18	(144)	1	(143)
Earnings	79	(3)	76	400	(6)	394
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(45)	-	(45)	(96)	1	(95)
Earnings attributable to Enbridge Inc.	34	(3)	31	304	(5)	299
Earnings attributable to Enbridge Inc. common shareholders	11	(3)	8	302	(5)	297
Earnings per common share attributable to Enbridge Inc. common shareholders	0.01	-	0.01	0.40	(0.01)	0.39
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.01	-	0.01	0.40	(0.01)	0.39

(unaudited; millions of Canadian dollars, except per share amounts)	Six months ended June 30, 2012 As Previously Reported	Adjustment	As Revised	Six months ended June 30, 2011 As Previously Reported	Adjustment	As Revised
Transportation and other services revenues	1,908	(4)	1,904	2,102	(5)	2,097
Depreciation and amortization	590	20	610	551	21	572
Income from equity investments	72	17	89	109	12	121
Income taxes expense	(12)	1	(11)	(247)	3	(244)
Earnings	438	(6)	432	833	(11)	822
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(125)	-	(125)	(163)	1	(162)
Earnings attributable to Enbridge Inc.	313	(6)	307	670	(10)	660
Earnings attributable to Enbridge Inc. common shareholders	275	(6)	269	666	(10)	656
Earnings per common share attributable to Enbridge Inc. common shareholders	0.36	(0.01)	0.35	0.89	(0.02)	0.87
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.35	-	0.35	0.88	(0.02)	0.86

(unaudited; millions of Canadian dollars, except per share amounts)	Three months ended September 30, 2012 As Previously Reported	Adjustment	As Revised	Three months ended September 30, 2011 As Previously Reported	Adjustment	As Revised
Transportation and other services revenues	910	(2)	908	888	(2)	886
Depreciation and amortization	293	8	301	272	10	282
Income from equity investments	32	8	40	31	6	37
Income taxes recovery/(expense)	(2)	-	(2)	24	1	25
Earnings	328	(2)	326	58	(5)	53
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(108)	-	(108)	(62)	-	(62)
Earnings attributable to Enbridge Inc.	220	(2)	218	(4)	(5)	(9)
Earnings attributable to Enbridge Inc. common shareholders	189	(2)	187	(5)	(5)	(10)
Earnings per common share attributable to Enbridge Inc. common shareholders	0.24	-	0.24	(0.01)	-	(0.01)
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.24	-	0.24	(0.01)	-	(0.01)

(unaudited; millions of Canadian dollars, except per share amounts)	Nine months ended September 30, 2012 As Previously Reported	Adjustment	As Revised	Nine months ended September 30, 2011 As Previously Reported	Adjustment	As Revised
Transportation and other services revenues	2,818	(6)	2,812	2,990	(7)	2,983
Depreciation and amortization	883	28	911	823	31	854
Income from equity investments	104	25	129	140	18	158
Income taxes expense	(14)	1	(13)	(223)	4	(219)
Earnings	766	(8)	758	891	(16)	875
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(233)	-	(233)	(225)	1	(224)
Earnings attributable to Enbridge Inc.	533	(8)	525	666	(15)	651
Earnings attributable to Enbridge Inc. common shareholders	464	(8)	456	661	(15)	646
Earnings per common share attributable to Enbridge Inc. common shareholders	0.60	(0.01)	0.59	0.88	(0.02)	0.86
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.59	-	0.59	0.87	(0.02)	0.85

(unaudited; millions of Canadian dollars, except per share amounts)	Year ended December 31, 2012 As Previously Reported	Adjustment	As Revised	Year ended December 31, 2011 As Previously Reported	Adjustment	As Revised
Transportation and other services revenues	4,295	(7)	4,288	4,536	(8)	4,528
Depreciation and amortization	1,206	36	1,242	1,112	42	1,154
Income from equity investments	160	35	195	210	23	233
Income taxes expense	(128)	1	(127)	(526)	6	(520)
Earnings	943	(7)	936	1,242	(21)	1,221
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(228)	(1)	(229)	(409)	2	(407)
Earnings attributable to Enbridge Inc.	715	(8)	707	833	(19)	814
Earnings attributable to Enbridge Inc. common shareholders	610	(8)	602	820	(19)	801
Earnings per common share attributable to Enbridge Inc. common shareholders	0.79	(0.01)	0.78	1.09	(0.02)	1.07
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	0.78	(0.01)	0.77	1.08	(0.03)	1.05

(unaudited; millions of Canadian dollars, except per share amounts)	Year ended December 31, 2010 As Previously Reported	Adjustment	As Revised
Transportation and other services recovery	3,843	(4)	3,839
Depreciation and amortization	1,017	22	1,039
Income from equity investments	228	4	232
Income taxes expense	(227)	4	(223)
Earnings	781	(18)	763

Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	170	4	174
Earnings attributable to Enbridge Inc.	951	(14)	937
Earnings attributable to Enbridge Inc. common shareholders	944	(14)	930
Earnings per common share attributable to Enbridge Inc. common shareholders	1.27	(0.01)	1.26
Diluted earnings per common share attributable to Enbridge Inc. common shareholders	1.26	(0.02)	1.24

	As at December 31, 2012			As at December 31, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(unaudited; millions of Canadian dollars)						
Long-term investments	3,386	(211)	3,175	3,081	(248)	2,833
Deferred amounts and other assets	2,622	(161)	2,461	2,500	(116)	2,384
Deferred income tax liabilities	2,601	(118)	2,483	2,615	(116)	2,499
Retained earnings	3,464	(291)	3,173	3,926	(284)	3,642
Accumulated other comprehensive loss	(1,799)	37	(1,762)	(1,532)	36	(1,496)

3. CHANGES IN ACCOUNTING POLICIES

BALANCE SHEET OFFSETTING

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

ACCUMULATED OTHER COMPREHENSIVE INCOME

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

FUTURE ACCOUNTING POLICY CHANGES

Obligations Resulting from Joint and Several Liability Arrangements

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

Parent s Accounting for the Cumulative Translation Adjustment

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

4. SEGMENTED INFORMATION

Three months ended March 31, 2013	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate1	Consolidated
(millions of Canadian dollars)						
Revenues	**544**	**1,066**	**4,643**	**1,764**	**-**	**8,017**
Commodity and gas distribution costs	**-**	**(666)**	**(4,568)**	**(1,164)**	**-**	**(6,398)**
Operating and administrative	**(238)**	**(134)**	**(41)**	**(260)**	**9**	**(664)**
Depreciation and amortization	**(100)**	**(79)**	**(15)**	**(124)**	**(4)**	**(322)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**(183)**	**-**	**(183)**
	206	**187**	**19**	**33**	**5**	**450**
Income from equity investments	**25**	**-**	**33**	**13**	**30**	**101**
Other income/(expense)	**10**	**1**	**15**	**(3)**	**(71)**	**(48)**
Interest expense	**(71)**	**(40)**	**(18)**	**(93)**	**(33)**	**(255)**
Income taxes recovery/(expense)	**(22)**	**(41)**	**(20)**	**(12)**	**33**	**(62)**
Earnings/(loss)	**148**	**107**	**29**	**(62)**	**(36)**	**186**
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**-**	**104**	**-**	**103**
Preference share dividends	**-**	**-**	**-**	**-**	**(39)**	**(39)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**147**	**107**	**29**	**42**	**(75)**	**250**
Additions to property, plant and equipment	**767**	**102**	**138**	**445**	**5**	**1,457**

Three months ended March 31, 2012	Liquids Pipelines2	Gas Distribution	Gas Pipelines, Processing and Energy Services2,3	Sponsored Investments2	Corporate1,3	Consolidated
(millions of Canadian dollars)						
Revenues	594	917	3,286	1,828	-	6,625
Commodity and gas distribution costs	-	(560)	(3,457)	(1,203)	-	(5,220)
Operating and administrative	(212)	(127)	(35)	(260)	2	(632)
Depreciation and amortization	(94)	(83)	(15)	(105)	(3)	(300)
Environmental costs, net of recoveries	-	-	-	(3)	-	(3)
	288	147	(221)	257	(1)	470
Income/(loss) from equity investments	1	-	36	15	(6)	46
Other income/(expense)	4	(5)	13	15	59	86
Interest expense	(62)	(41)	(11)	(98)	(5)	(217)
Income taxes recovery/(expense)	(47)	(23)	78	(45)	8	(29)
Earnings/(loss)	184	78	(105)	144	55	356
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	(1)	(78)	-	(80)
Preference share dividends	-	-	-	-	(15)	(15)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	183	78	(106)	66	40	261
Additions to property, plant and equipment	301	94	163	257	1	816

1 *Included within the Corporate segment was Interest income of $92 million (2012 - $78 million) charged to other operating segments.*

2 *In December 2012, certain crude oil storage and renewable energy assets were transferred to Enbridge Income Fund within the Sponsored Investments segment. Earnings from the assets for the three months ended March 31, 2012 of $9 million have not been reclassified among segments for presentation purposes.*

3 Due to a change in organizational structure, effective January 1, 2013 the Company s power transmission business is now reported under the Gas Pipelines, Processing and Energy Services segment. As a result, for the three months ended March 31, 2012, earnings of $nil and additions to property, plant and equipment of $16 million were reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment.

TOTAL ASSETS

(millions of Canadian dollars)	**March 31, 2013**	December 31, 2012
Liquids Pipelines	**16,410**	15,124
Gas Distribution	**7,233**	7,416
Gas Pipelines, Processing and Energy Services[1]	**6,095**	5,349
Sponsored Investments	**16,228**	15,648
Corporate[1]	**2,741**	3,263
	48,707	46,800

1 At December 31, 2012, Property, plant and equipment of $342 million relating to the power transmission business was reclassified from the Corporate segment to the Gas Pipelines, Processing and Energy Services segment as a result of the change in the organizational structure.

5. CREDIT FACILITIES

March 31, 2013 (millions of Canadian dollars)	Maturity Dates[2]	Total Facilities	Draws[3]	Available
Liquids Pipelines	2014	**300**	**26**	**274**
Gas Distribution	2014	**712**	**458**	**254**
Sponsored Investments	2014-2017	**3,648**	**1,565**	**2,083**
Corporate	2014-2017	**9,248**	**1,974**	**7,274**
		13,908	**4,023**	**9,885**
Southern Lights project financing[1]	2014	**1,516**	**1,452**	**64**
Total credit facilities		**15,424**	**5,475**	**9,949**

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

2 Total facilities include $35 million in demand facilities with no maturity date.

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

Credit facilities carry a weighted average standby fee of 0.2% 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 2017.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,334 million (December 31, 2012 - $2,925 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

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6. SHARE CAPITAL

PREFERENCE SHARES

(millions of Canadian dollars; number of preference shares in millions)	March 31, 2013 Number of Shares	Amount	December 31, 2012 Number of Shares	Amount
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**	-	-
Issuance costs		**(87)**		(78)
Balance at end of period		**4,109**		3,707

Characteristics of the preference shares are as follows:

(Canadian dollars unless otherwise stated)	Initial Yield	Dividend1	Per Share Base Redemption Value2	Redemption and Conversion Option Date2,3	Right to Convert Into3,4
Preference Shares, Series A	5.5%	$1.375	$25	-	-
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.0%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R	4.0%	$1.000	$25	June 1, 2019	Series S
Preference Shares, Series 15	4.0%	US$1.000	US$25	June 1, 2018	Series 2

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) or 2.5% (Series S)); or US$25 x (number of days in quarter/365) x (90-day United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M) or 3.1% (Series 2)).

5 A cash dividend of US$0.1808 per share will be payable on June 1, 2013 to Series 1 shareholders. The regular quarterly dividend of US$0.25 per share will begin in the third quarter of 2013.

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 18 million (2012 - 26 million) for the three months ended March 31, 2013, 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 March 31,	
	2013	2012
(number of shares in millions)		
Weighted average shares outstanding	**789**	757
Effect of dilutive options	**12**	12
Diluted weighted average shares outstanding	**801**	769

For the three months ended March 31, 2013, 6,353,550 anti-dilutive stock options (2012 - 5,759,150) with a weighted average exercise price of $44.85 (2012 - $38.32) were excluded from the diluted earnings per common share calculation.

7. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in AOCI attributable to Enbridge common shareholders for the three months ended March 31, 2013 and 2012 are as follows:

	Cash Flow Hedges	Net Investment Hedges	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	**78**	**(28)**	**127**	**2**	**-**	**179**
Other comprehensive income reclassified to earnings						
Interest rate contracts1	**43**	**-**	**-**	**-**	**-**	**43**
Commodity contracts2	**1**	**-**	**-**	**-**	**-**	**1**
Amortization of pension and OPEB actuarial loss3	**-**	**-**	**-**	**-**	**13**	**13**
	122	**(28)**	**127**	**2**	**13**	**236**
Tax impact						
Income tax on amounts retained in AOCI	**(20)**	**4**	**-**	**-**	**-**	**(16)**
Income tax on amounts reclassified to earnings	**(12)**	**-**	**-**	**-**	**(4)**	**(16)**
	(32)	**4**	**-**	**-**	**(4)**	**(32)**
Balance at March 31, 2013	**(531)**	**450**	**(1,138)**	**(24)**	**(315)**	**(1,558)**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2012	(476)	461	(1,167)	(28)	(286)	(1,496)
Other comprehensive income/(loss) retained in AOCI	182	10	(74)	-	-	118
Other comprehensive income reclassified to earnings						
Interest rate contracts1	11	-	-	-	-	11
Amortization of pension and OPEB actuarial loss3	-	-	-	-	7	7
	193	10	(74)	-	7	136
Tax impact						

Income tax on amounts retained in AOCI	(47)	(1)	-	(5)	-	(53)
Income tax on amounts reclassified to earnings	(1)	-	-	-	(1)	(2)
	(48)	(1)	-	(5)	(1)	(55)
Balance at March 31, 2012	(331)	470	(1,241)	(33)	(280)	(1,415)

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

2 *Reported within Commodity costs in the Consolidated Statements of Earnings.*

3 *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.*

8. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE 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 price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

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

Foreign Exchange Risk

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

Interest Rate Risk

The Company s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2017 with an average swap rate of 2.2%.

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 2016. A total of $10,547 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.5%.

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

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, crude oil, power and 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 balance sheet location and carrying value of the Company s derivative instruments. The Company did not have any outstanding fair value hedges at March 31, 2013 or December 31, 2012.

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

March 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	**4**	**17**	**93**	**114**	**(15)**	**99**
Interest rate contracts	**19**	**-**	**10**	**29**	**(11)**	**18**
Commodity contracts	**12**	**-**	**141**	**153**	**(57)**	**96**
Other contracts	**3**	**-**	**10**	**13**	**-**	**13**
	38	**17**	**254**	**309**	**(83)**	**226**
Deferred amounts and other assets						
Foreign exchange contracts	**11**	**59**	**118**	**188**	**(72)**	**116**
Interest rate contracts	**54**	**-**	**10**	**64**	**(30)**	**34**
Commodity contracts	**6**	**-**	**61**	**67**	**(39)**	**28**
Other contracts	**4**	**-**	**3**	**7**	**-**	**7**
	75	**59**	**192**	**326**	**(141)**	**185**
Accounts payable and other						
Foreign exchange contracts	**(4)**	**-**	**(21)**	**(25)**	**15**	**(10)**
Interest rate contracts	**(662)**	**-**	**(5)**	**(667)**	**11**	**(656)**
Commodity contracts	**(10)**	**-**	**(287)**	**(297)**	**57**	**(240)**
	(676)	**-**	**(313)**	**(989)**	**83**	**(906)**
Other long-term liabilities						
Foreign exchange contracts	**(28)**	**(8)**	**(71)**	**(107)**	**72**	**(35)**
Interest rate contracts	**(257)**	**-**	**(13)**	**(270)**	**30**	**(240)**
Commodity contracts	**(3)**	**-**	**(484)**	**(487)**	**39**	**(448)**
	(288)	**(8)**	**(568)**	**(864)**	**141**	**(723)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(17)**	**68**	**119**	**170**	**-**	**170**
Interest rate contracts	**(846)**	**-**	**2**	**(844)**	**-**	**(844)**
Commodity contracts	**5**	**-**	**(569)**	**(564)**	**-**	**(564)**
Other contracts	**7**	**-**	**13**	**20**	**-**	**20**
	(851)	**68**	**(435)**	**(1,218)**	**-**	**(1,218)**

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

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

March 31, 2013	2013	2014	2015	2016	2017	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**734**	**468**	**25**	**25**	**413**	**6**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,733**	**2,402**	**2,751**	**2,323**	**2,557**	**5,420**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	**5**	**-**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**2,394**	**3,603**	**3,467**	**3,168**	**2,852**	**171**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**4,590**	**3,055**	**1,760**	**1,142**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**43**	**40**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**69**	**44**	**11**	**10**	**11**	**5**
Commodity contracts - crude oil *(millions of barrels)*	**18**	**37**	**29**	**23**	**18**	**9**
Commodity contracts - NGL *(millions of barrels)*	**2**	**2**	**-**	**-**	**-**	**-**
	51	**67**	**48**	**63**	**83**	**66**

Commodity contracts - power *(megawatt hours (MWH))*	

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

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

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

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**14**	19
Interest rate contracts	**79**	180
Commodity contracts	**-**	(8)
Other contracts	**2**	(1)
Net investment hedges		
Foreign exchange contracts	**(22)**	3
	73	193
Amount of (gains)/loss reclassified from AOCI to earnings *(effective portion)*		
Interest rate contracts1	**13**	14
Commodity contracts2	**-**	2
	13	16
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts1	**38**	-
Commodity contracts2	**(1)**	(2)
	37	(2)

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

2 Reported within Commodity costs in the Consolidated Statements of Earnings.

The Company estimates that $112 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 60 months at March 31, 2013.

Non-Qualifying Derivatives

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

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Foreign exchange contracts[1]	**(193)**	15
Interest rate contracts[2]	**(4)**	(2)
Commodity contracts[3]	**(53)**	(203)
Other contracts[4]	**6**	-
Total unrealized derivative fair value loss	**(244)**	(190)

1 Reported within Transportation and other services revenues and Other income in the Consolidated Statements of Earnings.

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

3 Reported within Transportation and other services revenues, 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 the Company will not be able to meet its financial obligations, including commitments, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper 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 one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at March 31, 2013. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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:

(millions of Canadian dollars)	**March 31, 2013**	December 31, 2012
Canadian financial institutions	**391**	306
United States financial institutions	**253**	129
European financial institutions	**89**	244
Other[1]	**117**	128
	850	807

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

As at March 31, 2013, the Company had provided letters of credit totaling $237 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company holds no cash collateral on asset exposures at March 31, 2013 or December 31, 2012.

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

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. 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 DERIVATIVES

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. The Company does not have any other financial instruments categorized as Level 1.

Level 2

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

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. 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:

March 31, 2013	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**114**	**-**	**114**
Interest rate contracts	**-**	**29**	**-**	**29**
Commodity contracts	**4**	**35**	**114**	**153**
Other contracts	**-**	**13**	**-**	**13**
	4	**191**	**114**	**309**
Long-term derivative assets				
Foreign exchange contracts	**-**	**188**	**-**	**188**
Interest rate contracts	**-**	**64**	**-**	**64**
Commodity contracts	**-**	**56**	**11**	**67**
Other contracts	**-**	**7**	**-**	**7**
	-	**315**	**11**	**326**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(25)**	**-**	**(25)**
Interest rate contracts	**-**	**(667)**	**-**	**(667)**
Commodity contracts	**(8)**	**(194)**	**(95)**	**(297)**
	(8)	**(886)**	**(95)**	**(989)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(107)**	**-**	**(107)**
Interest rate contracts	**-**	**(270)**	**-**	**(270)**
Commodity contracts	**-**	**(408)**	**(79)**	**(487)**
	-	**(785)**	**(79)**	**(864)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**170**	**-**	**170**
Interest rate contracts	**-**	**(844)**	**-**	**(844)**
Commodity contracts	**(4)**	**(511)**	**(49)**	**(564)**
Other contracts	**-**	**20**	**-**	**20**
	(4)	**(1,165)**	**(49)**	**(1,218)**

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

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

March 31, 2013	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
(Fair value in millions of Canadian dollars)						
Commodity contracts - financial1						
Natural gas	4	Forward gas price	3.81	4.66	4.37	$/mmbtu3
Crude	(8)	Forward crude price	70.37	114.66	85.49	$/barrel
NGL	7	Forward NGL price	0.30	2.15	1.32	$/gallon
Power	(64)	Forward power price	41.50	76.50	55.13	$/MWH
Commodity contracts - physical1						
Natural gas	(18)	Forward gas price	3.37	5.07	4.15	$/mmbtu3
Crude	27	Forward crude price	69.91	121.04	92.31	$/barrel
NGL	(2)	Forward NGL price	0.02	2.37	1.27	$/gallon
Power	(1)	Forward power price	31.55	38.86	34.46	$/MWH
Commodity options2						
Natural gas	1	Option volatility	33%	36%	35%	
NGL	5	Option volatility	34%	108%	51%	
	(49)					

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:

	Three months ended March 31,	
	2013	2012
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**(24)**	32
Total gains/(loss)		
Included in earnings[1]	**(36)**	18
Included in OCI	**1**	2
Settlements	**10**	(5)
Level 3 net derivative asset/(liability) at end of period	**(49)**	47

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 March 31, 2013 or 2012.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totaled $68 million at March 31, 2013 (December 31, 2012 - $66 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $282 million at March 31, 2013 (December 31, 2012 - $246 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. At March 31, 2013, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2012 - $580 million).

At March 31, 2013, the Company s long-term debt had a carrying value of $21,205 million (December 31, 2012 - $20,855 million) and a fair value of $25,211 million (December 31, 2012 - $24,809 million).

9. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2013 is 25.0% (2012 - 7.5%). In 2012, the effective rate reflected significant losses relating to certain risk management activities in the Company s United States operations and the higher United States income tax rate over the Canadian federal statutory rate. Those losses did not persist in the three months ended March 31, 2013.

10. 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 March 31,	
	2013	2012
(millions of Canadian dollars)		
Benefits earned during the period	**28**	19
Interest cost on projected benefit obligations	**22**	13
Expected return on plan assets	**(26)**	(14)
Amortization of prior service costs	**1**	-
Amortization of actuarial loss	**13**	6
Net benefit costs on an accrual basis[1,2]	**38**	24

1 *Included in net benefit costs for the three months ended March 31, 2013 are costs related to OPEB of $4 million (2012 - $3 million).*

2 *For the three months ended March 31, 2013, offsetting regulatory assets of $1 million (2012 - $5 million) are recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.*

11. CONTINGENCIES

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 21.1% combined direct and indirect ownership interest in Enbridge Energy Partners, L.P. (EEP), which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Lakehead System Crude Oil Releases

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 of 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.

As at March 31, 2013, and as previously disclosed in March 2013, EEP s total cost estimate for the Line 6B crude oil release was US$995 million ($161 million after-tax attributable to Enbridge) which is an increase of US$175 million ($24 million after-tax attributable to Enbridge) compared with the December 31, 2012 estimate. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the Pipeline and Hazardous Materials Safety Administration (PHMSA) civil penalty of US$3.7 million which was paid in the third quarter of 2012. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) (the Order) which defined the scope requiring additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. EEP submitted its initial proposed work plan required by the EPA on April 4, 2013, resubmitted the work plan on April 23, 2013 and is waiting for a response from the EPA. EEP does not believe these refinements in the work plan will materially change its cost estimate. The Order states the work must be completed by December 31, 2013.

The US$175 million increase in the total cost estimate is attributable to additional work required by the Order. The actual costs incurred may differ from the foregoing estimate as EEP discusses its work plan with the EPA and works with other regulatory agencies to assure its work plan complies with their requirements. Any such incremental costs will not be recovered under EEP s insurance policies as the expected costs for the incident will exceed the limits of its insurance coverage.

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

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. The May 1 insurance renewal programs include commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP s remediation spending through March 31, 2013, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

In the first quarter of 2012, EEP received payments of US$50 million ($7 million after-tax attributable to Enbridge) for insurance receivable claims previously recognized as a reduction to environmental costs in 2011. For the three month period ended March 31, 2013, EEP did not receive any payments for insurance receivable claims. As at March 31, 2013, EEP has recorded total insurance recoveries of US$505 million for the Line 6B crude oil release. EEP expects to record receivables for additional amounts claimed for recovery pursuant to its insurance policies during the period that EEP deems realizations of the claim for recovery to be probable.

Enbridge s current comprehensive insurance program, under which EEP is insured, expired April 30, 2013 and had a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability. Enbridge has renewed its comprehensive property and liability insurance programs effective May 1, 2013 through April 30, 2014. The renewed coverage for the liability program has an aggregate limit of US$685 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 the Enbridge entities on an equitable basis based on an insurance allocation agreement EEP has entered into with Enbridge and another Enbridge subsidiary.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Approximately 30 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, EEP does not expect the outcome of these actions to be material. As noted above, on July 2, 2012, PHMSA announced a Notice of Probable Violation related to the Line 6B crude oil release, including a civil penalty of US$3.7 million that EEP paid in the third quarter of 2012. One claim related to the Line 6A crude oil release has been filed against one of EEP s affiliates by the State of Illinois in the Illinois state court. The parties are currently operating under an agreed interim order.

TAX MATTERS

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

OTHER 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.

12. SUBSEQUENT EVENTS

On April 5, 2013, the Company acquired a 50% interest in the Blackspring Ridge Wind Project, a 300 megawatt wind energy project located in Alberta, for cash consideration of $104 million.

On April 16, 2013, the Company issued 13 million Common Shares for gross proceeds of approximately $600 million.