ENBRIDGE INC
Form 6-K
May 09, 2012

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

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

the Securities Exchange Act of 1934

Dated May 9, 2012

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

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

3000, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

(403) 231-3900

(Registrants telephone number, including area code)

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

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

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

Yes No **P**

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

Yes No **P**

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

Yes No **P**

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

N/A

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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- Press Release dated May 9, 2012
- Interim Report to Shareholders for the three months ended March 31, 2012.

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 9, 2012

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

NEWS RELEASE

Enbridge reports first quarter adjusted earnings of $376 million or $0.50 per common share

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars)

- First quarter earnings were $264 million including unrealized non-cash mark-to-market losses
- First quarter adjusted earnings increased 14% to $376 million
- U.S. Gulf Coast access initiative upsized to a $5.2 billion investment
- Acquisition of a 100% interest in the 50-megawatt Silver State North Solar Project development in Nevada
- Issuance of $1.05 billion in preference shares
- Enbridge named one of the Global 100 Most Sustainable Corporations, one of Canada s Greenest Employers and a member of the FTSE4Good Index

CALGARY, ALBERTA, May 9, 2012 Enbridge Inc. (TSX:ENB) (NYSE:ENB) With first quarter adjusted earnings of $376 million, or $0.50 per share, Enbridge begins 2012 firmly on track to achieve our full year adjusted earnings guidance of $1.58 to $1.74 per share, said Patrick D. Daniel, Chief Executive Officer.

First quarter 2012 earnings of $264 million included unrealized non-cash mark-to-market losses, primarily related to the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions. These short-term non-cash fluctuations in reported earnings are a result of Enbridge s hedging program, which over the long-term will support the Company s reliable cash flows and capacity for ongoing dividend growth.

In the first quarter, Enbridge announced it had received sufficient commitments from shippers to upsize its proposed Flanagan South Pipeline Project and, with joint venture partner, Enterprise Products Partners, L.P. (Enterprise) to twin the Seaway Crude Pipeline System, bringing Enbridge s expected investment in its U.S. Gulf Coast initiative to $5.2 billion.

The commitments secured in the open seasons held in the fourth quarter of last year and the first quarter of 2012 will support additional infrastructure to meet the growing transportation needs of Bakken and western Canadian producers and U.S. Gulf Coast refiners, contributing to North America s energy security, said Mr. Daniel. The new upsized Flanagan South Pipeline, combined with our existing Spearhead Pipeline system, will offer shippers 775,000 barrels per day of capacity from Flanagan to Cushing, with the Seaway Crude Pipeline System reversal and expansion offering capacity of 850,000 barrels per day from Cushing to the Gulf Coast.

By leveraging existing infrastructure wherever possible, impacts to landowners, communities and the environment will be minimized, added Mr. Daniel.

Forward-Looking Information

This news release contains forward-looking information. Significant related assumptions and risk factors are described under the Forward-Looking Information section of this news release.

In green energy, Enbridge added to its growing portfolio of renewable generation assets with the acquisition of a 100% interest in the Silver State North Solar Project (Silver State) development in Nevada.

Silver State marks Enbridge s entry into the U.S. solar energy market, which offers significant growth opportunities given the excellent solar resource, supportive regulatory environment and expanding portfolio of solar energy projects, said Mr. Daniel. The project complements Enbridge s growing portfolio of renewable and alternative energy technologies that now includes interests in eight wind farms, four solar projects, a hybrid fuel cell, geothermal and four waste heat recovery facilities. Together, Enbridge has interests in a renewable energy portfolio of almost 1,000 megawatts.

During the quarter, Enbridge continued to be active in capital markets. Noted Mr. Daniel, Over the past eight months Enbridge has issued $2 billion in preference shares, bolstering our balance sheet as we embark upon the largest slate of growth projects we ve ever had before us.

In January, Enbridge was recognized as one of the Corporate Knights Global 100 Most Sustainable Corporations, and in March, FTSE Group reaffirmed Enbridge s membership in the FTSE4Good Index series which identifies companies that meet globally recognized corporate responsibility standards. In April, Enbridge was named one of Canada s Greenest Employers.

It is gratifying to be recognized for the sustainability of our business model, our commitment to delivering on our social responsibilities, and our continuing efforts to minimize the environmental impact of our activities, said Mr. Daniel. Enbridge s more than 7,000 employees work tirelessly to achieve our vision of being the leading energy delivery company in North America. I thank all of them for their outstanding work and continuing commitment to our corporate values and to Corporate Social Responsibility.

Enbridge continues to deliver strong financial performance across our liquids pipelines, gas pipelines and processing, gas distribution and green energy businesses, concluded Mr. Daniel. We have had exceptional success in securing new projects across all of our business units, we are well positioned to fund our growth and, with a strong start to the year, we expect to continue to deliver superior returns to our investors.

FIRST QUARTER 2012 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.

• The decrease in earnings from $364 million for the first quarter of 2011 to $264 million for the first quarter of 2012 was primarily due to the recognition of net unrealized fair value losses of $110 million (2011 - nil) from the revaluation of financial derivatives related to the Company s risk management activities. Contributing to the overall decrease in earnings were lower earnings from Enbridge Gas Distribution (EGD) due to warmer weather. Partially offsetting these quarter-over-quarter declines were increased earnings from Liquids Pipelines as a result of favourable operating performance under the Competitive Toll Settlement.

• Enbridge s first quarter adjusted earnings increased 14% to $376 million as a result of increased contributions from Canadian Mainline, which benefited from strong volumes, continued positive performance at EGD reflecting favourable operating performance, and an increase in earnings from Enbridge Energy Partners, L.P. due to stronger results from the liquids and natural gas businesses, as well as higher incentive income. Corporate earnings also contributed to increased first quarter adjusted earnings due to the Company s increased investment in Noverco Inc. (Noverco) and lower residual financing costs.

• On May 7, 2012, Enbridge announced Silver State began commercial operation. A 100% interest in the 50-megawatt Silver State development in Clark County, Nevada, was acquired in March 31, 2012 at an estimated cost of $0.2 billion. Located 65 kilometers (40 miles) south of Las Vegas, Nevada, Silver State was being constructed under a fixed-price engineering, procurement and construction agreement with First Solar, and is expected to begin commercial operation in the second quarter of 2012. First Solar will provide operations and maintenance services under a long-term contract. NV Energy will purchase the energy output under a 25-year power purchase agreement.

• On April 19, 2012, Enbridge announced the closing of the issue of eight million cumulative redeemable preference shares, series J at a price of US$25 per share for aggregate gross proceeds of US$200 million.

• On April 16, 2012, the Government of New Brunswick enacted a final rates and tariffs regulation which set limits on gas distribution rates within the province. Enbridge had advised on March 12, 2012, when the regulation was still in draft form, that it faced a potential write down of a significant portion of the value of its investment in Enbridge Gas New Brunswick (EGNB), the New Brunswick gas distribution utility. With the finalization of the regulation, Enbridge has confirmed a write down of $262 million. The impact of this charge was recognized as a subsequent event in the Company s 2011 United States generally accepted accounting principles (U.S. GAAP) consolidated financial statements, voluntarily filed on May 2, 2012.

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB, commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen s Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the Province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen s Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. There is no assurance these actions will be successful or will result in any recovery.

- On March 29, 2012, Enbridge closed its offering of cumulative redeemable preference shares, series H. Due to strong investor demand, the size of the offering was increased to 14 million shares, for aggregate gross proceeds of $350 million.

- Enbridge announced on March 26, 2012, its intent to upsize the capacity of its U.S. Gulf Coast Access projects. The Flanagan South Pipeline from Flanagan, Illinois to Cushing, Oklahoma will be upsized to a 36-inch diameter line with an initial annual capacity of 585,000 barrels per day (bpd). Enbridge, with joint venture partner Enterprise will construct an 805-kilometre (500-mile), 30-inch diameter twin (a parallel line) along the route of their jointly owned Seaway Pipeline, adding 450,000 bpd of capacity to the existing system. The partners will also proceed with construction of an extension from Houston to Port Arthur/Beaumont, adding 560,000 bpd of capacity to that system. The total estimated cost of the Flanagan South Pipeline project, as a result of the larger capacity and pipeline size, has increased from the original US$1.9 billion to

US$2.8 billion. In addition, the Enbridge share of the cost of the Seaway Pipeline twin line and extension is expected to be approximately US$1.0 billion.

The increased Flanagan South Pipeline and Seaway Pipeline capacity is required to accommodate additional commitments for Gulf Coast service, originating from both Flanagan and Cushing, received through recently completed second open seasons. Both the Flanagan South Pipeline and Seaway twin pipeline are expected to be in service by mid-2014.

Enterprise and Enbridge are nearing completion of the first phase of the reversal of the Seaway Pipeline, which will provide 150,000 bpd of southbound takeaway capacity from Cushing to the Gulf Coast, anticipated to be in service in May 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter 2013, capacity would increase to 400,000 bpd depending upon the mix of light and heavy grades of crude oil.

• On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering. Enbridge s share of the proceeds of approximately $317 million, expected to be received as a dividend from Noverco in the second quarter of 2012, will be used to pay a portion of the Company s quarterly dividend on June 1, 2012.

• On February 27, 2012, the Board of Directors of Enbridge announced that Patrick D. Daniel, President and Chief Executive Officer (CEO), will retire at or before the end of 2012. The Board also announced the appointment of Al Monaco, previously President, Gas Pipelines, Green Energy and International, to Enbridge s Board of Directors and to the position of President, effective February 27, 2012. Mr. Daniel will continue as CEO and a member of the Board until his retirement.

• On February 23, 2012, Enbridge welcomed the publication of Transport Canada s TERMPOL Review Process Report of the proposed Northern Gateway Project s proposed marine operations. Transport Canada has filed the results of the study with the federal Joint Review Panel (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 Project. 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. Further review of the Northern Gateway application by the JRP, as well as other agencies, is ongoing.

• On January 18, 2012, Enbridge closed the offering of cumulative redeemable preference shares, series F. Due to strong investor demand, the size of the offering was increased to 20 million shares, resulting in aggregate gross proceeds of $500 million.

CONFERENCE CALL

Enbridge will hold a conference call on Wednesday, May 9, 2012 at 9:00 a.m. Eastern Time (7:00 a.m. Mountain Time) to discuss the first quarter 2012 results. Analysts, members of the media and other interested parties can access the call at 617-213-8059 or toll-free at 1-866-825-1692 using the access code of 47854821. The call will be audio webcast live at **www.media-server.com/m/p/wd35mvqp**. 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 at toll-free 1-888-286-8010 or 617-801-6888 (access code 17767809) will be available until May 16, 2012.

The conference call will begin with presentations by the Company s Chief Executive Officer, the President 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.

The unaudited interim Consolidated Financial Statements and MD&A, which contain additional notes and disclosures, are available on the Enbridge website at www.enbridge.com/InvestorRelations.aspx.

Enbridge Inc., a Canadian company, is a North American leader in delivering energy and one of the Global 100 Most Sustainable Corporations. 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. Enbridge employs more than 7,000 people, primarily in Canada and the U.S., and is ranked as one of Canada s Greenest Employers and one of the Top 100 Companies to Work for in Canada. 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 or adjusted earnings; expected earnings or adjusted earnings per share; 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 that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas and natural gas liquids (NGL); prices of crude oil, natural gas and NGL; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project 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 and NGL, 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,

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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 or adjusted earnings 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 dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

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, 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 non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that 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.

Enbridge Contacts:

Media
Jennifer Varey
(403) 508-6563 or Toll Free: 1-888-992-0997
Email: jennifer.varey@enbridge.com

Investment Community
Jody Balko
(403) 231-5720
Email: jody.balko@enbridge.com

HIGHLIGHTS

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars, except per share amounts)		
Earnings attributable to common shareholders		
Liquids Pipelines	**191**	136
Gas Distribution	**78**	102
Gas Pipelines, Processing and Energy Services	**(111)**	26
Sponsored Investments	**66**	55
Corporate	**40**	45
	264	364
Earnings per common share[1]	**0.35**	0.49
Diluted earnings per common share[1]	**0.34**	0.48
Adjusted earnings[2]		
Liquids Pipelines	**158**	136
Gas Distribution	**102**	91
Gas Pipelines, Processing and Energy Services	**36**	39
Sponsored Investments	**67**	53
Corporate	**13**	11
	376	330
Adjusted earnings per common share[1]	**0.50**	0.44
Cash flow data		
Cash provided by operating activities	**648**	1,163
Cash used in investing activities	**(928)**	(647)
Cash provided by/(used in) financing activities	**663**	(301)
Dividends		
Common share dividends declared	**221**	188
Dividends paid per common share[1]	**0.2825**	0.2450
Shares outstanding *(millions)*		
Weighted average common shares outstanding[1]	**757**	750
Diluted weighted average common shares outstanding[1]	**769**	758
Operating data		
Liquids Pipelines - Average deliveries *(thousands of barrels per day)*		
Canadian Mainline[3]	**1,687**	1,602
Regional Oil Sands System[4]	**333**	329
Spearhead Pipeline	**144**	160
Gas Distribution - Enbridge Gas Distribution		
Volumes *(billions of cubic feet)*	**161**	193
Number of active customers *(thousands)*[5]	**2,001**	1,974
Heating degree days[6]		
Actual	**1,490**	1,966
Forecast based on normal weather	**1,770**	1,802
Gas Pipelines, Processing and Energy Services - Average throughput volume *(millions of cubic feet per day)*		
Alliance Pipeline US	**1,632**	1,677
Vector Pipeline	**1,754**	1,752
Enbridge Offshore Pipelines	**1,501**	1,751

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

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.

ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

March 31, 2012

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2012

This Management s Discussion and Analysis (MD&A) dated May 8, 2012 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, 2012, prepared in accordance with United States generally accepted accounting principles (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements, which were prepared in accordance with Part V Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook (Part V), and MD&A contained in the Company s Annual Report for the year ended December 31, 2011, as well as the consolidated financial statements for the year ended December 31, 2011 that were prepared in accordance with U.S. GAAP and filed on a voluntary basis to facilitate understanding of the Company s transition to U.S. GAAP. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

CONSOLIDATED EARNINGS

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**191**	136
Gas Distribution	**78**	102
Gas Pipelines, Processing and Energy Services	**(111)**	26
Sponsored Investments	**66**	55
Corporate	**40**	45
Earnings attributable to common shareholders	**264**	364
Earnings per common share[1]	**0.35**	0.49
Diluted earnings per common share[1]	**0.34**	0.48

1 Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.

Earnings attributable to common shareholders were $264 million for the three months ended March 31, 2012, or $0.35 per common share, compared with $364 million, or $0.49 per common share, for the three months ended March 31, 2011. The decrease in earnings was primarily due to the recognition of unrealized fair value losses within Energy Services related to the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions and revaluation of inventory. Contributing to the overall decrease in earnings were lower earnings from Enbridge Gas Distribution (EGD) due to warmer weather. Partially offsetting these quarter-over-quarter declines were increased earnings from Liquids Pipelines as a result of favourable operating performance under the Competitive Toll Settlement (CTS) and recognition of unrealized fair value gains in Canadian Mainline related to the risk management of exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices. Also, income taxes were lower for the three months ended March 31, 2012 compared with the three months ended March 31, 2011 primarily due to a decrease in the effective income tax rate as a result of losses arising on certain risk management activities in the Company s United States operations.

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FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide the Company s shareholders and potential investors with information about the Company and its subsidiaries and affiliates, including management s assessment of Enbridge s and its subsidiaries future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as anticipate , expect , project , estimate , forecast , plan , intend , target , believe and sim 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 or adjusted earnings; expected earnings or adjusted earnings 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 and natural gas liquids (NGL); prices of crude oil, natural gas and NGL; expected exchange rates; inflation; interest rates; the availability and price of labour and pipeline construction materials; operational reliability; customer project 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 and NGL, 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 or adjusted earnings 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 dates, and expected capital expenditures include: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

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, 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 non-recurring or non-operating factors on both a consolidated and segmented basis. These factors are reconciled and discussed in the financial results sections for the affected business segments. Management believes that 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.

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ADJUSTED EARNINGS

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**158**	136
Gas Distribution	**102**	91
Gas Pipelines, Processing and Energy Services	**36**	39
Sponsored Investments	**67**	53
Corporate	**13**	11
Adjusted earnings	**376**	330
Adjusted earnings per common share[1]	**0.50**	0.44

1 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

Adjusted earnings were $376 million, or $0.50 per common share, for the three months ended March 31, 2012 compared with $330 million, or $0.44 per common share, for the three months ended March 31, 2011. The increase resulted from positive contributions from almost all of the Company s business segments, including:

- Within Liquids Pipelines, increased contributions from Canadian Mainline which benefited from strong volumes, as well as from Feeder Pipelines and Other.

- Continued positive performance at EGD reflecting favourable operating performance under the current Incentive Regulation term as well as an increased contribution from Enbridge Gas New Brunswick (EGNB) due to seasonal winter demand. Under the new regulations to which EGNB is subject, rate regulated accounting no longer applies and EGNB earnings will reflect variability from seasonal demand.

- Within Sponsored Investments, increased contributions from Enbridge Energy Partners, L.P. (EEP), due to higher volumes and tolls, and increased contributions from Enbridge Income Fund (the Fund) due to the acquisition and strong operating performance of certain renewable energy assets.

- In Corporate, higher preference share dividends were more than offset by lower residual financing costs and stronger results from Noverco Inc. (Noverco), resulting in an overall increase in adjusted earnings.

RECENT DEVELOPMENTS

CHIEF EXECUTIVE OFFICER SUCCESSION PLANS

On February 27, 2012, the Board of Directors announced that Patrick D. Daniel, President and Chief Executive Officer (CEO), will retire at or before the end of 2012. The Board also announced the appointment of Al Monaco, previously President, Gas Pipelines, Green Energy and International, to Enbridge s Board of Directors and to the position of President, effective February 27, 2012. Mr. Daniel will continue as CEO and a member of the Board until his retirement. With Mr. Monaco s appointment as President, Leon Zupan was appointed President, Gas Pipelines.

LIQUIDS PIPELINES

Southern Lights Pipeline

Both the Canadian and United States uncommitted rates on Southern Lights Pipeline for 2010, 2011 and 2012 were challenged by Exxon Mobil and Imperial Oil. The Canadian Southern Lights toll hearing was held before National Energy Board (NEB) panel members in November 2011. On February 9, 2012, the NEB issued its decision rejecting the challenge from uncommitted shippers stating that tolls in place are just and reasonable and more recently approved the 2010, 2011 and 2012 interim tolls as final. A Federal Energy Regulatory Commission (FERC) hearing was held in January 2012. Briefs were filed on February 27 and March 28, 2012 and an initial decision is expected on or before June 5, 2012. No material financial impact to the Company is anticipated to result from the FERC proceeding.

Norman Wells Pipeline Crude Oil Release

The Norman Wells Pipeline is a 12-inch, 39,400 barrels per day (bpd) line transporting sweet crude oil that stretches 869 kilometres (540 miles) from Norman Wells, Northwest Territories (NWT) to Zama, Alberta. On May 9, 2011, Enbridge reported a crude oil release from the Norman Wells Pipeline approximately 50 kilometres (31 miles) south of the community of Wrigley, NWT. On May 20, 2011, Enbridge returned the Norman Wells line to service after completing necessary repairs. Excavation of all contaminated soils from the spill site was completed in late November 2011. Based on the volume of contaminated materials removed from the site, the current estimate of volume released is approximately 1,600 barrels. Site reclamation work is anticipated to be completed in the summer of 2012. Monitoring of surface water and groundwater at the site will continue until remediation and reclamation goals have been achieved in accordance with plans filed with the regulator. Currently, Management does not believe this incident will have a material impact on the Company s consolidated financial position or results of operations.

GAS DISTRIBUTION

Enbridge Gas New Brunswick Regulatory Matters

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

A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick on April 16, 2012. Based on the amendments to the rate setting methodology outlined therein EGNB will no longer meet the criteria for the continuation of rate regulated accounting. As a result, the Company must eliminate from its consolidated statements of financial position a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an income tax recovery of $21 million.

As the final rates and tariffs regulation published on April 16, 2012 provided further evidence of a condition that existed on December 31, 2011, recognition of the charge totaling $262 million, after tax, was reflected as a subsequent event in the Company s U.S. GAAP consolidated financial statements for the year ended December 31, 2011, which were voluntarily filed with the Canadian Securities Administrators and the United States Securities and Exchange Commission (SEC) on May 2, 2012. The charge reflects Management s best estimate based on facts available at this time and may be subject to further revision based on future actions or interpretations of the regulator, the Government of New Brunswick or other factors.

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB, commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen s Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the Province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen s Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. There is no assurance these actions will be successful or will result in any recovery.

SPONSORED INVESTMENTS

EEP Lakehead System Line 6A and 6B Crude Oil Releases

Enbridge holds an approximate 23% combined direct and indirect ownership interest in EEP. Under U.S. GAAP, Enbridge consolidates EEP and its earnings, net of noncontrolling interests, are reflected within the Sponsored Investments segment.

Line 6B Crude Oil Release

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with extended submerged oil recovery operations, including reassessment, remediation and restoration of the area and air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

The total cost estimate for this incident remains at approximately US$765 million ($129 million after-tax attributable to Enbridge) at March 31, 2012 based on a review of costs and commitments incurred coupled with the evaluation of additional information regarding requirements for environmental restoration and remediation. Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at March 31, 2012. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at US$48 million ($7 million after-tax attributable to Enbridge), before any third party or insurance recoveries and excluding fines and penalties.

EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP s remediation spending through March 31, 2012, Enbridge and its affiliates have exceeded the limits of its 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 insurance 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. At March 31, 2012, EEP had collected total insurance recoveries of US$335 million ($50 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to EEP s insurance policies during the period that EEP deems realization of the claim for recovery to be probable. In the first quarter of 2011, EEP recognized insurance recoveries of US$35 million ($5 million after-tax attributable to Enbridge) for claims that it filed while no such recoveries were recognized during the first quarter of 2012.

Enbridge s current comprehensive insurance program, expiring April 30, 2012, has a current liability aggregate limit of US$575 million, including pollution liability. Enbridge will renew its liability insurance and expects to increase the aggregate limit of coverage effective May 1, 2012 through April 30, 2013.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, these actions are not expected to be material. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at March 31, 2012. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

Enbridge Income Fund

Saskatchewan System Shipper Complaint

On December 17, 2010, the Saskatchewan System filed amended Westspur tariffs with the NEB with an effective date of February 1, 2011. In January 2011, a shipper on the Westspur System requested the NEB make the tolls interim effective February 1, 2011 pending discussions between the shipper and the Saskatchewan System on information requests put forward by the shipper. Subsequently, the shipper filed a complaint with the NEB on the basis the information provided by the Saskatchewan System was not adequate to allow for an assessment to be made of the reasonableness of the tolls. Six parties have filed letters with the NEB supporting the shipper s complaint. The NEB directed additional discussion among the parties and, as of May 7, 2012, the Fund continues to discuss the reasonableness of its Westspur tolls with shippers.

CORPORATE

Noverco

Noverco holds, directly and indirectly, an investment in Enbridge common shares. Noverco had advised Enbridge that the substantial increase in the value of these shares over the last decade resulted in a significant shift in the balance of Noverco s asset mix. The Board of Directors of Noverco authorized the Caisse de Depot et Placement de Quebec, as manager of Noverco, to sell a portion of its Enbridge common share holding and rebalance Noverco s asset mix. On March 22, 2012 Noverco sold 22.5 million Enbridge common shares through a secondary offering. Enbridge s share of the proceeds of approximately $317 million, expected to be received as a dividend from Noverco in the second quarter of 2012, will be used to pay a portion of the Company s quarterly dividend on June 1, 2012. *See Liquidity and Capital Resources Financing Activities.*

Preference Share Issuances

Series F

On January 18, 2012, the Company issued 20 million Preference Shares, Series F for gross proceeds of $500 million. The 4.0% Cumulative Redeemable Preference Shares, Series F are entitled to a fixed, cumulative, quarterly preferential dividend of $1 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding preference shares for $25 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 F will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series G, subject to certain conditions, on June 1, 2018 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series G will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate plus 2.51%.

Series H

On March 29, 2012, the Company issued 14 million Preference Shares, Series H for gross proceeds of $350 million. The 4.0% Cumulative Redeemable Preference Shares, Series H are entitled to a fixed, cumulative, quarterly preferential dividend of $1 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding preference shares for $25 per share plus all accrued and unpaid dividends on September 1, 2018 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series H will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series I, subject to certain conditions, on September 1, 2018 and on September 1 of every fifth year thereafter. The holders of Preference Shares, Series I will be entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate plus 2.12%.

Series J

On April 19, 2012, the Company issued eight million Preference Shares, Series J for gross proceeds of US$200 million. The 4.0% Cumulative Redeemable Preference Shares, Series J are entitled to a fixed, cumulative, quarterly preferential dividend of US$1 per share per annum. The Company may, at its option, redeem all or a portion of the outstanding preference shares for US$25 per share plus all accrued and unpaid dividends on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series J will have the right to convert their shares into Cumulative Redeemable Preference Shares, Series K, subject to certain conditions, on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Preference Shares, Series K will be entitled to receive quarterly floating rate cumulative dividends at a rate equal the sum of the then 90-day US Government Treasury bill rate plus 3.05%.

GROWTH PROJECTS

The table below summarizes the current status of the Company s commercially secured projects, in each of the Company s business segments.

		Actual/ Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1.	Edmonton Terminal Expansion	$0.3 billion	$0.1 billion	2012	Under construction
2.	Woodland Pipeline	$0.3 billion	$0.2 billion	2012	Substantially complete
3.	Wood Buffalo Pipeline	$0.4 billion	$0.2 billion	2012	Under construction
4.	Seaway Crude Pipeline System (including reversal, expansion and extension)	US$2.4 billion	US$1.2 billion	2012-2014 (in phases)	Under construction
5.	Waupisoo Pipeline Capacity Expansion	$0.4 billion	$0.2 billion	2012-2013 (in phases)	Under construction
6.	Norealis Pipeline	$0.5 billion	$0.1 billion	2013	Under construction
7.	Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.1 billion	2013-2014 (in phases)	Pre-construction
8.	Flanagan South Pipeline Project	US$2.8 billion	No significant expenditures to date	2014	Pre-construction
9.	Athabasca Pipeline Twinning	$1.2 billion	No significant expenditures to date	2015	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES					
10.	Silver State North Solar Project	US$0.2 billion	US$0.2 billion	2012	Complete
11.	Lac Alfred Wind Project	$0.3 billion	$0.1 billion	2012-2013 (in phases)	Under construction

12.	Cabin Gas Plant	$1.1 billion	$0.5 billion	2012-2014 (in phases)	Under construction

		Actual/ Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
13.	Tioga Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
14.	Venice Condensate Stabilization Facility	US$0.2 billion	No significant expenditures to date	2013	Pre-construction
15.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.1 billion	2014	Pre-construction
16.	Big Foot Oil Pipeline	US$0.2 billion	No significant expenditures to date	2014	Pre-construction
SPONSORED INVESTMENTS					
17.	EEP - Bakken Expansion Program	US$0.4 billion	US$0.1 billion	2013	Under construction
18.	The Fund - Bakken Expansion Program	$0.2 billion	No significant expenditures to date	2013	Pre-construction
19.	EEP - Cushing Terminal Storage Expansion Project	US$0.1 billion	US$0.1 billion	2012	Under construction
20.	EEP - South Haynesville Shale Expansion	US$0.3 billion	US$0.2 billion	2012+	Under construction
21.	EEP - Line 5 Expansion	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
22.	EEP - Ajax Cryogenic Processing Plant	US$0.2 billion	No significant expenditures to date	2013	Under construction
23.	EEP - Bakken Access Program	US$0.1 billion	No significant expenditures to date	2013	Under construction
24.	EEP - Berthold Rail Project	US$0.1 billion	No significant expenditures to date	2013	Pre-construction
25.	EEP - Texas Express Pipeline	US$0.4 billion	No significant expenditures to date	2013	Under construction
26.	EEP - Line Replacement Program	US$0.3 billion	No significant expenditures to date	2013	Pre-construction
CORPORATE					
27.	Montana-Alberta Tie-Line	US$0.4 billion	US$0.3 billion	2012-2013 (in stages)	Under construction

1 These amounts are estimates only and subject to upward or downward adjustment based on various factors. As 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, 2012.

LIQUIDS PIPELINES

Edmonton Terminal Expansion

The Edmonton Terminal Expansion Project involves expanding the tankage of the mainline terminal at Edmonton, Alberta by one million barrels at an estimated cost of $0.3 billion, with expenditures to date of approximately $0.1 billion. The expansion is required to accommodate growing oil sands production receipts both from Enbridge s Waupisoo Pipeline and other non-Enbridge pipelines. The expansion will be conducted over two phases and will consist of the construction of four tanks and the installation of three booster pumps and related infrastructure. Regulatory approval was received in the first quarter of 2011 and the expansion is expected to be completed by December 2012.

Woodland Pipeline

Enbridge entered into a joint venture agreement with Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties to provide for the transportation of blended bitumen from the Kearl oil sands mine to crude oil hubs in the Edmonton, Alberta area. The project will be phased with the mine expansion, with the first phase involving construction of a new 140-kilometre (87-mile) 36-inch diameter pipeline from the mine to the Cheecham Terminal, and service on Enbridge s existing Waupisoo Pipeline from Cheecham to the Edmonton area. The new Woodland Pipeline may be extended from Cheecham to Edmonton as part of future industry expansions. Regulatory approval for the Phase I facilities was received in June 2010 and construction is substantially complete. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, of which Enbridge s share is approximately $0.3 billion. Enbridge s share of total project expenditures to date is approximately $0.2 billion. Enbridge expects the pipeline will come into service in late 2012.

Wood Buffalo Pipeline

Enbridge entered into an agreement with Suncor Energy Inc. (Suncor) to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal adjacent to Suncor s oil sands plant to the Cheecham Terminal, which is the origin point of Enbridge s Waupisoo Pipeline. The Waupisoo Pipeline already delivers crude oil from several oil sands projects to the Edmonton mainline hub. The new Wood Buffalo Pipeline will parallel the existing Athabasca Pipeline between the Athabasca and Cheecham Terminals. The estimated capital cost is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion. Construction of the pipeline was substantially completed in the first quarter of 2012, with in service expected by late 2012 upon completion of the related facilities.

Seaway Crude Pipeline System

Acquisition of Interest

In 2011, Enbridge acquired a 50% interest in the Seaway Pipeline system at a cost of approximately US$1.2 billion. The 1,078-kilometre (670-mile) Seaway Pipeline includes the 805-kilometre (500-mile), 30-inch diameter long-haul system from Freeport, Texas to Cushing, Oklahoma, as well as the Texas City Terminal and Distribution System which serves refineries in the Houston and Texas City areas. Seaway Pipeline also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast and four import docks at two locations. The other 50% interest in the Seaway Pipeline system is owned by Enterprise Products Partners L.P. (Enterprise).

Reversal

In December 2011, Enbridge and Enterprise announced plans to reverse the flow direction of the 805-kilometre (500-mile) 30-inch diameter Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the U.S. Gulf Coast. 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 Enterprise s ECHO crude oil terminal (ECHO Terminal) southeast of Houston. Enbridge s expected cost for the reversal is approximately US$0.2 billion. The initial 150,000 bpd of capacity on the reversed system is expected to be available by the second quarter of 2012. Following pump station additions and modifications, which are expected to be completed by the first quarter of 2013, capacity would increase to 400,000 bpd depending upon the mix of light and heavy grades of crude oil.

Expansion and Extension

In March 2012, Enbridge and Enterprise, based on additional capacity commitments from shippers, announced plans to proceed with an expansion of the Seaway Pipeline through construction of a second line that will more than double its capacity to 850,000 bpd by mid-2014. This 30-inch diameter pipeline will twin the existing Seaway system following the same routing.

In addition, a proposed 137-kilometre (85-mile) pipeline is expected to be built 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 lateral will offer incremental capacity of 560,000 bpd and is expected to be available in early 2014. Enbridge s investment to twin the pipeline and for the Port Arthur lateral is expected to be approximately US$1.0 billion.

Waupisoo Pipeline Capacity Expansion

The Waupisoo Pipeline Capacity Expansion, which received regulatory approval in November 2010, is expected to provide 65,000 bpd of additional capacity in the second half of 2012 and an estimated 190,000 bpd of additional capacity in the second half of 2013 when the expansion is fully in service. The estimated cost of the project is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion.

Norealis Pipeline

In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the Company will construct a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the proposed 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 $0.1 billion. With regulatory approval received in the second quarter of 2011, the project is expected to be in service in late 2013.

Athabasca Pipeline Capacity Expansion

The Company will undertake an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including incremental production from the Christina Lake Oilsands Project operated by Cenovus. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on the type of crude oil. The estimated cost of full expansion is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion and an expected in service date of 2013 for an initial 430,000 bpd of capacity. The balance of additional capacity 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.

Flanagan South Pipeline Project

The Flanagan South Pipeline will transport crude oil from the Company s terminal at Flanagan, Illinois to Cushing, Oklahoma. Based on the results of a second open season held in the first quarter of 2012, the Flanagan South Pipeline will be upsized to a 36-inch diameter line with an initial annual capacity of 585,000 bpd, increasing the total expected cost of the project from the original US$1.9 billion to US$2.8 billion. Subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014. Both the Seaway and Flanagan South pipelines are included in the Company s Gulf Coast Access initiative to offer crude oil transportation from its terminal at Flanagan to the United States Gulf Coast.

Athabasca Pipeline Twinning

This project includes twinning the southern section of the Company s Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to accommodate the need for additional capacity to serve the Kirby Lake area expected oil sands growth. The expansion project, with an estimated cost of approximately $1.2 billion, will include 345 kilometres (210 miles) of 36-inch pipeline within the existing Athabasca Pipeline right-of-way. The initial annual capacity of the twin pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. The line is expected to enter service in 2015.

Northern Gateway Project

The Northern Gateway Project involves constructing a twin 1,177-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine and tank 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. The JRP conducted sessions with the public, including Aboriginal groups, to receive comments on the draft List of Issues, additional information which Northern Gateway should be required to file and locations for the oral hearings. The JRP decided to obtain these comments prior to issuing a Hearing Order or initiating further procedural steps in the joint review process. In January 2011, the JRP issued a decision requiring Northern Gateway to provide certain additional information on the design and risk assessment of the pipelines before it would issue a Hearing Order. This information, together with other updates regarding the project, was provided to the JRP in March 2011 and the JRP issued a Hearing Order in May 2011 outlining the procedures to be followed.

In June 2011, Northern Gateway filed additional materials with the JRP including, but not limited to, details of its extensive program of consultation with over 40 Aboriginal communities between December

2009 and March 2011. The update summarized the information provided to Aboriginal groups, the engagement activities that have occurred, the interests and concerns that have been expressed to Northern Gateway, commitments and mitigation measures in response to those concerns and an update on the status of Aboriginal Traditional Knowledge study programs. 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 interveners and government participants.

In a Procedural Direction issued in December 2011, the JRP indicated community hearings would be scheduled so the Panel will hear all oral evidence from registered interveners first, followed by oral statements from registered participants. Community hearings for oral evidence took place between January and April 2012. After the Panel has heard all oral evidence, it will then hear oral statements in various communities. A written record of what is said each day in the community hearings is available on the Panel s website. The Panel expects to hold final hearings in September and October 2012 where Northern Gateway, interveners, government participants and the JRP will question those who have presented oral or written evidence. Final Argument is proposed for April 2013. Based on this projected schedule, the JRP would anticipate releasing the Environmental Assessment in the fall of 2013 and its final decision on this project near the end of 2013. 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 by 2017 at the earliest, at an estimated cost of $5.5 billion. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.2 billion, including $0.1 billion in funding secured from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project. Given the many uncertainties surrounding the Northern Gateway Project, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

On February 23, 2012, Transport Canada s published its TERMPOL Review Process Report of the proposed Northern Gateway Project 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 Project. 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. Further review of the Northern Gateway application by the JRP, as well as other agencies, is ongoing.

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 Project 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 Project website or Enbridge s website is incorporated in or otherwise part of this MD&A.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Silver State North Solar Project

In March 2012, Enbridge acquired a 100% interest in the development of the 50-megawatt (MW) Silver State North Solar Project, located 65 kilometres (40 miles) south of Las Vegas, Nevada. The project, which began commercial operation in May 2012, was constructed under a fixed-price engineering, procurement and construction agreement with First

Solar. First Solar will provide operations and maintenance services under a long-term contract. NV Energy will purchase the energy output under a 25-year power purchase agreement (PPA). The Company s total investment in the project is expected to be approximately US$0.2 billion.

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 will take place in two phases: Phase 1 is expected to be completed in December 2012; while Phase 2 is expected to be completed in December 2013. Hydro-Quebec will purchase the power under a 20-year PPA and will construct the 30-kilometre transmission line to connect Lac Alfred to the grid under an interconnection agreement. The Company s total investment in the project is expected to be approximately $0.3 billion.

Cabin Gas Plant

In December 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 is expected to be approximately $1.1 billion. Phase 1 of the development is to have 400 million cubic feet per day (mmcf/d) of processing capacity. The plant is currently under construction and is expected to be in-service in late 2012. Phase 2, which is to provide an additional 400 mmcf/d of capacity, has been sanctioned by the producers and has also received regulatory approval. Phase 2 is expected to be ready for service in the third quarter of 2014. Capacity for both phases 1 and 2 has been fully subscribed by Horn River producers. These producers can request the Company to expand Cabin up to an additional four phases, under agreed terms.

Tioga Lateral Pipeline

Alliance Pipeline US plans to develop 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. Through its 50% ownership interest in Alliance Pipeline US, Enbridge s expected cost related to the project is approximately US$0.1 billion. Alliance Pipeline US has executed a precedent agreement with Hess Corporation (Hess) as an anchor shipper on the Tioga Lateral Pipeline. Aux Sable Liquids Products (Aux Sable) and Hess have reached a concurrent agreement for the provision of NGL services. The 124-kilometre (77-mile) Tioga Lateral Pipeline will facilitate movement of high-energy, liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of the Alliance mainline system. The pipeline will have an initial design capacity of approximately 106 mmcf/d, which can be expanded based on shipper demand. On January 25, 2012, Alliance Pipeline US filed an application for regulatory approval to construct and operate the Tioga Lateral and, pending approvals, the pipeline is expected to be in service by mid-2013.

Venice Condensate Stabilization Facility

The Company plans for an estimated US$0.2 billion expansion of the Venice Condensate Stabilization Facility (Venice) at its Venice, Louisiana facility within its Offshore business. The expanded condensate processing capacity will be required to accommodate additional natural gas production from the recently sanctioned 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 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.

Walker Ridge Gas Gathering System

The Company executed definitive agreements 2010 with Chevron USA, Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deepwater 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 0.1 billion cubic feet per day. WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.1 billion.

Big Foot Oil Pipeline

The Company executed definitive agreements in the 2011 with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc. to construct and operate a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the proposed Big Foot ultra-deepwater development in the Gulf of Mexico. This crude oil pipeline project is complementary to Enbridge s plans to construct the WRGGS. The estimated cost of the Big Foot Oil Pipeline, which will be located about 274 kilometres (170 miles) south of the coast of Louisiana, is approximately US$0.2 billion and it is expected to be in service in 2014.

SPONSORED INVESTMENTS

Bakken Expansion Program

A joint project to further expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba is being undertaken by EEP and the Fund. The Bakken Expansion Program is expected to provide capacity of 145,000 bpd and, together with the North Dakota mainline, is expected to result in a total takeaway capacity of 355,000 bpd for this region. The Bakken Expansion Program involves United States projects undertaken by EEP at a cost of approximately US$0.4 billion and will involve Canadian projects undertaken by the Fund at a cost of approximately $0.2 billion. Regulatory approval has been received and construction commenced in July 2011 on the United States portion of the project, with expenditures to date of approximately US$0.1 billion. In Canada, NEB approval was secured in December 2011. Subject to other approvals in respect of the Canadian portion, the Bakken Expansion Program is expected to be completed in the first quarter of 2013. On February 28, 2012, the Fund and EEP announced a second open season for the Bakken Expansion Program which closed on April 18, 2012. The open season resulted in additional term commitments to support the project.

Enbridge Energy Partners, L.P.

Cushing Terminal Storage Expansion Project

EEP is constructing 13 new storage tanks at its Cushing Terminal with an approximate shell capacity of 4.4 million barrels. The total estimated cost of the expansion is approximately US$0.1 billion. As of April 30, 2012, nine tanks had been completed and placed into service and the last remaining tanks are expected to come into service by December 2012.

South Haynesville Shale Expansion

EEP is expanding its East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage. The expansion, with an estimated cost of approximately US$0.1 billion, is expected to increase capacity of EEP s East Texas system by 900 mmcf/d upon completion in 2012.

EEP plans to invest an additional US$0.2 billion to expand its East Texas system, including the construction of gathering and related treating facilities. EEP has signed long-term agreements with four major natural gas producers along the Texas side of the

Haynesville shale to provide gathering, treating and transmission services. Completion of the additional expansion is dependent on drilling plans of these producers. In light of weak gas prices and lower levels of producer activity, EEP has now deferred portions of its Haynesville natural gas expansion pending increases in drilling activity.

Line 5 Expansion and Line 9 Reversal

Enbridge and EEP will undertake two projects to provide increased access to refineries in the United States upper mid-west and in Ontario for light crude oil produced in western Canada and the United States. One project involves the expansion of EEP s 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. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of its Line 9 in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at a cost of approximately $20 million.

Subject to regulatory and other approvals, the Line 5 expansion is targeted to be in service during the first quarter of 2013, while the Line 9 reversal is targeted to be in service in late 2013.

Ajax Cryogenic Processing Plant

EEP is constructing an additional processing plant and other facilities on its Anadarko System at an approximate cost of US$0.2 billion. The Ajax Plant, with a planned capacity of 150 mmcf/d, is expected to be in service in early 2013. The Ajax Plant, when operational, in addition to the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d.

Bakken Access Program

The Bakken Access Program, a series of projects totaling approximately US$0.1 billion, represents an upstream expansion that will further complement EEP s Bakken expansion. This expansion program will enhance gathering capabilities on the North Dakota System by 100,000 bpd. The program, which involves increasing pipeline capacities, construction of additional storage tanks and the addition of truck access facilities at multiple locations in western North Dakota, is expected to be in service by early 2013.

Berthold Rail Project

EEP is proceeding with the Berthold Rail Project, a US$0.1 billion investment that will provide an interim solution to shipper needs in the Bakken region. The project is expected to expand capacity into the Berthold Terminal by 80,000 bpd and includes the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing facilities. A regulatory filing is in progress and detailed design is proceeding to enable construction to commence in April 2012 with an expected in-service date by early 2013.

Texas Express Pipeline

The Texas Express Pipeline (TEP) is a joint venture with Enterprise, Anadarko Petroleum Corporation and DCP Midstream LLC to design and construct a new NGL pipeline, as well as two new NGL gathering systems which EEP will build and operate. 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. 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 central Texas Barnett Shale processing plants. Subject to regulatory approvals and finalization of commercial terms, the pipeline and portions of the gathering systems are expected to begin service in mid-2013.

Line 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 approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through EEP s tariff surcharge that is part of the system-wide rates of the Lakehead System. EEP subsequently revised the scope of this project to increase the cost by approximately US$30 million, which will bring the total capital for this replacement program to an estimated cost of US$316 million. The US$30 million of additional costs do not currently have recovery under the tariff surcharge.

CORPORATE

Montana-Alberta Tie-Line (MATL)

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 the buoyant power demand in Alberta. The total expected cost for both the first 300-MW phase of MATL and the expansion for an additional 250-MW to 300-MW has been increased to approximately US$0.4 billion, of which approximately half will be funded through a 30-year loan from the Western Area Power Administration of the United States Department of Energy. Expenditures to date are approximately US$0.3 billion. While the permits required for construction have been obtained, the approval in Canada is currently being updated to reflect a number of design modifications which require further consultation with land owners. Subject to these approvals, the system s north-bound capacity, which is fully contracted, is expected to be in-service in the fourth quarter of 2012.

Neal Hot Springs Geothermal Project

The Company has partnered with U.S. Geothermal Inc. to develop the 35-MW Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. The project is anticipated to be completed in the second quarter of 2012 and will deliver electricity to the Idaho Power grid under a 25-year PPA. Construction on the project has commenced and Enbridge will invest up to approximately US$33 million for an expected 41% interest in the project.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Canadian Mainline	**99**	82
Regional Oil Sands System	**27**	27
Southern Lights Pipeline	**17**	19
Spearhead Pipeline	**11**	10
Feeder Pipelines and Other	**4**	(2)
Adjusted earnings	**158**	136
Canadian Mainline - Line 9 tolling adjustment	**6**	-
Canadian Mainline - unrealized derivative fair value gains	**27**	-
Earnings	**191**	136

Canadian Mainline earnings for the first three months of 2012 were governed by the CTS (with the exception of Lines 8 and 9) whereas earnings for the first quarter of 2011 were governed by a series of agreements, the most significant being the Incentive Tolling Settlement applicable to the mainline system and the Terrace and Alberta Clipper agreements. Earnings under the CTS are subject to variability in throughput volume and operating costs. Canadian Mainline volumes during the first quarter of 2012 were higher than expected contributing to an increase in earnings relative to the prior year, partially offset by higher operating and administrative costs, due primarily to the timing of integrity work.

Supplemental information on Canadian Mainline adjusted earnings for the first quarter of 2012 is as follows:

	Three months ended March 31, 2012
(millions of Canadian dollars, unless otherwise noted)	
Revenues	**316**
Expenses	
Operating and administrative	**81**
Power	**29**
Depreciation and amortization	**54**
	164
	152
Other expense	**(3)**
Interest expense	**(31)**
	118
Income taxes	**(19)**
Adjusted earnings	**99**
International Joint Tariff (IJT) Benchmark Toll[1] *(United States dollars per barrel)*	**$3.85**
Lakehead System Local Toll[2] *(United States dollars per barrel)*	**$2.01**
Canadian Mainline IJT Residual Benchmark Toll[3] *(United States dollars per barrel)*	**$1.84**
Effective United States dollar to Canadian dollar exchange rate[4]	**0.96**

1 The 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.
2 Per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois.
3 Per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. The Canadian Mainline IJT residual toll for any shipment is the difference between the IJT toll for that shipment and the Lakehead System local toll for that shipment.
4 Inclusive of realized gains or losses on foreign exchange derivative financial instruments.

	Three months ended, March 31,	
	2012	2011
Throughput volume[1] *(thousand barrels per day (kbpd))*	**1,687**	1,602

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.

Canadian Mainline revenues included the portion of the system covered by the CTS as well as revenues from Lines 8 and 9 in eastern Canada. Line 8 and Line 9 are currently tolled on a separate basis and comprise a relatively small proportion of total Canadian Mainline revenues. CTS revenues include transportation revenues, the largest component, as well as allowance oil and revenues from receipt and delivery charges. Transportation revenues include revenues for volumes delivered off the Canadian Mainline at Gretna and on to the Lakehead System, to which Canadian Mainline IJT residual benchmark tolls apply, and revenues for volumes delivered to other western Canada delivery points, to which the Canadian Local Toll (CLT) applies. Despite the many factors which affect Canadian Mainline revenues, the primary determinants of those revenues will be throughput volume ex-Gretna, the United States dollar Canadian Mainline IJT residual benchmark toll applicable to those volumes and the effective foreign exchange rate at which resultant revenues are converted into Canadian dollars. The Company may utilize derivative financial instruments to hedge foreign exchange rate risk on United States dollar denominated revenues. The exact relationship between the primary determinants and actual Canadian Mainline revenues will vary somewhat from quarter to quarter but is expected to be relatively stable on average for a year, absent a systematic shift in receipt and delivery point mix or in crude oil type mix.

The largest components of operating and administrative expenses are employee related costs, pipeline integrity, repairs and maintenance, rents and leases and property taxes. Operating and administrative costs are relatively insensitive to throughput volumes. The primary drivers of future increases in operating costs are expected to be normal escalation in wage rates, prices for purchased services and tax rates, addition of new facilities and more extensive integrity and maintenance programs.

Power is the most significant variable operating cost and is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements. However, the primary determinants of power cost are the level of power prices in various jurisdictions and throughput volume. The relationship of power consumption to throughput volume is expected to be roughly proportional over a moderate range of volumes. The Company may utilize derivative financial instruments to hedge power prices.

Depreciation and amortization expense will adjust over time as a result of changes in estimated depreciation rates and additions to property, plant and equipment due to new facilities, as well as maintenance and integrity capital expenditures.

Canadian Mainline income taxes reflected current income taxes only. Under the CTS, the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment and, as such, an offsetting regulatory asset related to deferred income taxes is recognized as incurred.

The preceding financial overview includes expectations regarding future events and operating conditions that the Company believes are reasonable based on currently available information; however, such statements are not guarantees of future performance and are subject to change.

Prior to the implementation of the CTS, revenue on the Canadian Mainline was recognized in a manner consistent with the underlying agreements as approved by the regulator, in accordance with rate-regulated accounting. The Company discontinued the application of rate-regulated accounting to its Canadian Mainline (excluding Lines 8 and 9) on a prospective basis commencing July 1, 2011. The regulatory asset balance at the date of discontinuance related to tolling deferrals recognized in prior periods is being recovered through a surcharge to the CLT and IJT. While the CTS is based on previous tolling settlements and cost-of-service principles, earnings are subject to variability associated with throughput volume and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations (excluding Lines 8 and 9) no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. The regulatory asset of approximately $470 million related to deferred income taxes recorded at the date of discontinuance will continue to be recognized as the Company retains the ability to recover deferred income taxes under an NEB order governing flow-through income tax treatment. In the same manner, the rate order provides for the recovery of deferred income taxes incurred subsequent to the date of discontinuance and, as such, regulatory assets related to deferred income taxes will continue to be recognized as incurred.

The earnings increase in Feeder Pipelines and Other primarily reflected a higher contribution from Olympic Pipeline resulting from a tariff increase. In 2011, earnings from Toledo Pipeline were negatively impacted by integrity work on Lines 6A and 6B of EEP s Lakehead System.

Liquids Pipelines earnings were impacted by the following non-recurring or non-operating adjusting items.

- Canadian Mainline earnings for 2012 included a Line 9 tolling adjustment related to services provided in prior periods.

- Canadian Mainline earnings for 2012 reflected unrealized fair value gains on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.

GAS DISTRIBUTION

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Enbridge Gas Distribution (EGD)	**81**	78
Other Gas Distribution and Storage	**21**	13
Adjusted earnings	**102**	91
EGD - colder/(warmer) than normal weather	**(24)**	11
Earnings	**78**	102

The increase in EGD s adjusted earnings was primarily due to customer growth, lower interest expense and lower statutory income tax rates, partially offset by higher system integrity and operating and administrative costs as well as higher depreciation expense. In addition, compared with the prior year, lower per unit volumetric charges with corresponding increases in fixed charges are expected to modify EGD s quarterly earnings profile, but not materially impact full year earnings as earnings are shifted from the colder winter months to the warmer summer months.

Other Gas Distribution and Storage earnings increased primarily due to the discontinuance of rate regulated accounting for EGNB in the first quarter of 2012. This discontinuance will result in earnings being subject to increased variability, including quarterly seasonality, as there will be no further accumulation of the regulatory deferral account. Earnings will increase in the colder winter months when demand for natural gas is high and earnings will decrease in the warmer summer months when demand, and therefore delivered volumes, is low. As a result of recent amendments to the rate setting methodology to which EGNB is subject, on a full year basis, earnings are expected to be approximately 60% lower than the $20 million earned in 2011. *See Recent Developments Gas Distribution Enbridge Gas New Brunswick Regulatory Matters.*

Gas Distribution earnings were impacted by the following non-recurring or non-operating adjusting item.

- EGD earnings are adjusted to reflect the impact of weather.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Enbridge Offshore Pipelines (Offshore)	**3**	2
Alliance Pipeline US	**6**	7
Vector Pipeline	**5**	5
Aux Sable	**12**	11
Energy Services	**4**	9
Other	**6**	5
Adjusted earnings	**36**	39
Aux Sable - unrealized derivative fair value gains/(loss)	**7**	(6)
Energy Services - unrealized derivative fair value loss	**(154)**	(7)

Earnings/(loss)	**(111)**	26

Offshore adjusted earnings for the three months ended March 31, 2012 included a $2 million favourable impact related to the reversal of a shipper reserve pertaining to a rate case from 2011. Overall, Offshore is expected to be in a loss position for the full year as the Company continues to experience weak volumes due to the slower regulatory permitting process and delayed drilling programs by producers in the Gulf of Mexico.

Energy Services employs various marketing strategies to capture basis (location) differentials and tank management revenue when opportunities arise. Energy Services adjusted earnings declined in the first quarter of 2012 due to changing market conditions which gave rise to fewer margin opportunities in liquids marketing.

Gas Pipelines, Processing and Energy Services earnings were impacted by the following non-recurring or non-operating adjusting items.

- Aux Sable earnings for each period reflected unrealized fair value changes on derivative financial instruments related to the Company s forward gas processing risk management position.

- Energy Services earnings for each period reflected unrealized fair value gains and losses related to the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions and the revaluation of inventory.

SPONSORED INVESTMENTS

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Enbridge Energy Partners (EEP)	**36**	31
Enbridge Energy, Limited Partnership - Alberta Clipper US (EELP)	**10**	12
Enbridge Income Fund (the Fund)	**21**	10
Adjusted earnings	**67**	53
EEP - NGL trucking and marketing investigation costs	**(1)**	-
EEP - unrealized derivative fair value loss	**-**	(3)
EEP - leak insurance recoveries	**-**	5
EEP - lawsuit settlement	**-**	1
EEP - impact of unusual weather conditions	**-**	(1)
Earnings	**66**	55

EEP adjusted earnings for the first quarter of 2012 included strong results from the liquids and natural gas businesses, as well as higher incentive income. The increased earnings from the liquids business was primarily due to higher average daily delivery volumes and an increase in transportation rates on all major liquids systems. Earnings from the natural gas business increased as a result of higher natural gas and NGL volumes, in addition to improved processing margins, on the Anadarko System, partially due to new assets placed in service to process the growing natural gas production. These positive impacts were offset by an increase in operating and administrative costs, primarily workforce-related costs, as well as higher interest expense.

Earnings for the Fund for the first quarter of 2012 included earnings from the Ontario Wind, Sarnia Solar and Talbot Wind energy projects (the Renewable Assets) acquired from a wholly-owned subsidiary of Enbridge in October 2011. Prior to October 2011, earnings from the Renewable Assets were presented within the Gas Pipelines, Processing and Energy Services segment. Partially offsetting strong contributions from the Renewable Assets were increased interest costs associated with funding the acquisition as well as higher deferred income taxes.

Sponsored Investment earnings were impacted by the following non-recurring or non-operating adjusting items.

- EEP earnings for 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.

- Earnings from EEP for 2011 included a change in the unrealized fair value on derivative financial instruments in each period.

• Earnings from EEP for 2011 included insurance recoveries associated with the Line 6B crude oil release. *See Recent Developments Sponsored Investments EEP Lakehead System Line 6A and 6B Crude Oil Releases.*

• EEP earnings included proceeds related to the settlement of a lawsuit during the first quarter of 2011.

• EEP earnings for 2011 included an unfavourable effect related to decreased volumes due to uncharacteristically cold weather in February 2011 that disrupted normal operations of its natural gas systems.

CORPORATE

	Three months ended March 31	
	2012	2011
(millions of Canadian dollars)		
Noverco	**20**	14
Other Corporate	**(7)**	(3)
Adjusted earnings	**13**	11
Noverco - equity earnings adjustment	**(12)**	-
Other Corporate - unrealized derivative fair value gains	**10**	16
Other Corporate - foreign tax recovery	**29**	-
Other Corporate - unrealized foreign exchange gains on translation of intercompany balances, net	**-**	18
Earnings	**40**	45

Noverco adjusted earnings for the three months ended March 31, 2012 reflected contributions from the Company s increased preferred share investment.

The increase in Other Corporate adjusted loss was primarily due to an increase in preference share dividends following the issuance of 72 million preference shares since the first quarter of 2011, partially offset by lower net Corporate segment financing costs. In April 2012, the Company issued an additional eight million preference shares. *See Recent Developments Corporate Preference Share Issuances.*

Corporate costs were impacted by the following non-recurring or non-operating adjusting items.

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

• Earnings for each period included a change in the unrealized fair value gains on derivative financial instruments related to forward foreign exchange risk management positions.

• Earnings for the first quarter of 2012 were favourably impacted by a recovery of taxes related to a historical foreign investment.

• Earnings for the first quarter of 2011 included net unrealized foreign exchange gains on the translation of foreign-denominated intercompany balances.

LIQUIDITY AND CAPITAL RESOURCES

The Company 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. At March 31, 2012, excluding the Southern Lights project financing, the Company had $9,988 million of committed credit facilities of which $3,446 million were drawn or allocated to backstop commercial paper. Inclusive of unrestricted cash and cash equivalents of $875 million, the Company had net available liquidity at March 31, 2012 of $7,417 million. The net available liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently secured capital projects and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company s credit facilities at March 31, 2012.

	Maturity Dates[1]	Total Facilities	Credit Facility Draws[2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2013	**300**	**25**	**275**
Gas Distribution	2012-2013	**717**	**290**	**427**
Sponsored Investments	2013-2016	**2,498**	**737**	**1,761**
Corporate[3]	2013-2016	**6,473**	**2,394**	**4,079**
		9,988	**3,446**	**6,542**
Southern Lights project financing[4]	2013-2014	**1,505**	**1,442**	**63**
Total credit facilities		**11,493**	**4,888**	**6,605**

1 *Total facilities include $30 million in demand facilities with no maturity date.*
2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
3 *Includes a revolving credit facility of US$1.3 billion with a maturity date of 2015 that was secured in January 2012.*
4 *Total facilities inclusive of $60 million for debt service reserve letters of credit.*

OPERATING ACTIVITIES

Cash provided by operating activities was $648 million for the three months ended March 31, 2012 compared with $1,163 million for the three months ended March 31, 2011. The Company s growing cash flows from development projects placed into service in recent years, from the favourable operating performance of Canadian Mainline under CTS and from increased contributions from Sponsored Investments, was masked by variations in working capital accounts quarter-over-quarter. Changes in operating assets and liabilities contributed $700 million to the overall net decline in cash provided by operating activities for the first quarter of 2012 compared with the first quarter of 2011. Working capital will fluctuate from time to time due to natural gas inventory and borrowing levels at EGD, which in turn are impacted by weather and commodity prices, as well as activity levels within the Company s Energy Services businesses, among others. Other changes in operating assets and liabilities in the first quarter of 2012 included payment of tax balances remaining from 2011 and receipt of insurance payments for claims made in conjunction with the Line 6B crude oil release, collecting some of the cash outlays incurred in 2011.

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 $16 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities for the three months ended March 31, 2012 was $928 million compared with $647 million for the three months ended March 31, 2011. Cash used in investing activities included $877 million (2011 - $536 million) of additions to property, plant and equipment, primarily directed to the Company s growth projects which was partially offset by the timing of cash payments of construction payables. The increase in cash used in investing activities was also attributable to greater intangible asset additions, primarily software, and additional funding of various investments and joint ventures, namely the Texas Express and Woodland Pipelines.

FINANCING ACTIVITIES

Cash generated from financing activities was $663 million for the three months ended March 31, 2012 compared with cash used in financing activities of $301 million for the three months ended March 31, 2011. The increase in cash was primarily due to issuances of both preference shares and debenture and term notes of $826 million and $500 million, respectively. The Company accesses capital markets as required to finance currently secured capital projects and to provide flexibility for new growth opportunities. This increase was partially offset by higher net repayments of bank indebtedness and short-term borrowings and commercial paper and credit facility draws. Additionally, cash used in financing activities for the first quarter of 2012 included routine distributions to third party investors in EEP and the Fund of $100 million (2011 - $24 million) and $12 million (2011 - $7 million), respectively.

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, 2012, dividends declared were $221 million (2011 - $188 million), of which $156 million (2011 - $124 million) were paid in cash and reflected in financing activities. The remaining $65 million (2011 - $64 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, 2012, 29% (2011 - 34%) of total dividends declared were reinvested.

On April 26, 2012, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2012 to shareholders of record on May 15, 2012.

Common Shares[1]	$0.28250
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F[2]	$0.36990

1 *A portion of this common share dividend, estimated to be $0.2372 per share, will not qualify for the enhanced dividend tax credit in Canada and accordingly, will not be designated as an eligible dividend . This is because certain of the funds being distributed to shareholders will be sourced from funds received in the form of dividends from Noverco, a private company investee of Enbridge, following the profitable sale of some of Noverco s shares in Enbridge. The remaining portion of the dividend, currently estimated to be $0.0453 per share, will be designated as an eligible dividend for Canadian federal income tax purposes. The whole dividend of $0.2825 per share will still be a qualified dividend for United States tax purposes.*

2 *This first dividend declared for the Preference Shares, Series F includes accrued dividends from January 18, 2012, the date the shares were issued. The regular quarterly dividend of $0.25 per share will take effect on September 1, 2012. See Recent Developments Corporate Preference Share Issuances Series F.*

Capital Expenditure Commitments

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,935 million which are expected to be paid over the next five years.

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. 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 volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.32%.

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

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

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil 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.

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

Equity Price Risk

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

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	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**19**	(19)
Interest rate contracts	**180**	78
Commodity contracts	**(8)**	(56)
Other contracts	**(1)**	1
Net investment hedges		
Foreign exchange contracts	**3**	20
	193	24
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Cash flow hedges		
Interest rate contracts[1]	**14**	4
Commodity contracts[2]	**2**	(9)
	16	(5)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Cash flow hedges		
Commodity contracts[2]	**(2)**	1
	(2)	1
Amount of unrealized gain/(loss) recognized in earnings		
Non-qualifying derivatives		
Foreign exchange contracts[3]	**15**	22
Interest rate contracts[1]	**(2)**	-
Commodity contracts[2]	**(203)**	(34)
Other contracts[4]	**-**	(2)
Total unrealized derivative fair value loss	**(190)**	(14)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Transportation and other services revenue, Commodity costs, and Operating and administrative expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenue and Other income 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, 2012. 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.

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 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, the Company uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share 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.

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 several 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 NEB, the Company filed its estimates of 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). The NEB is also requiring regulated pipeline companies to file a proposed process for collecting and setting aside the funds for future abandonment costs by November 30, 2012 for Group 1 companies and by March 31, 2013 for Group 2 companies. These costs would be recovered from shippers through tolls in accordance with NEB s determination that abandonment costs are a legitimate cost of providing services and are recoverable upon NEB approval from users of the system.

Both of the required submissions will require NEB approval and will result in increased transportation tolls and regulatory liabilities. The specific toll impacts are uncertain at this time as they will be the subject of NEB filings in late 2012 and early 2013.

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.

CHANGE 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 an SEC registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

To facilitate users understanding of the transition to U.S. GAAP, the Company restated its 2011 consolidated financial statements, which were originally prepared in accordance with Part V, to U.S. GAAP, including full comparative information and related note disclosure. The 2011 U.S. GAAP financial statement were voluntarily filed with securities regulators in Canada and the United States on May 2, 2012 and are available on SEDAR at www.sedar.com and on the Company s website at www.enbridge.com. None of the information contained on, or connected to, Enbridge s website is incorporated or otherwise part of this MD&A.

Fair Value Measurement

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board s joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company s earnings or cash flows for the current or prior periods presented.

Statement of Comprehensive Income

Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and OCI either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company s presentation of comprehensive income and did not impact the Company s consolidated financial statements.

Goodwill Impairment

Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

QUARTERLY FINANCIAL INFORMATION

	2012[1]	2011[1]				2010[2]		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
(millions of Canadian dollars, except per share amounts)								
Revenues	**6,627**	7,237	6,278	6,937	6,529	4,193	3,493	3,518
Earnings attributable to common shareholders	**264**	159	(5)	302	364	326	157	138
Earnings per common share[3]	**0.35**	0.21	(0.01)	0.40	0.49	0.44	0.21	0.19
Diluted earnings per common share[3]	**0.34**	0.21	(0.01)	0.40	0.48	0.43	0.21	0.18
Dividends per common share[3]	**0.2825**	0.2450	0.2450	0.2450	0.2450	0.2125	0.2125	0.2125
EGD - warmer/(colder) than normal weather	**24**	12	-	(2)	(11)	(6)	-	10
Net unrealized derivative fair value and intercompany foreign exchange (gains)/losses	**110**	(251)	251	(17)	(18)	(71)	(45)	87

1 *Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*
2 *Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.*
3 *Comparative amounts were restated to reflect two-for-one stock split which was effective May 25, 2011.*

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

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

The Company actively manages its exposure to market 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, unrealized fair value gains and losses on these instruments will impact earnings. The revaluation of foreign-denominated intercompany loans also impacts earnings each quarter.

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*.

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 2011 earnings are the Company s share of leak remediation costs and lost revenue associated with the Line 6A and Line 6B crude oil releases in the amounts of $6 million, $21 million, and $6 million (2010 - nil, $85 million, and $21 million) in the second, third and fourth quarters, respectively. Earnings for 2011 also reflected insurance recoveries associated with the Line 6B crude oil release of $5 million, $3 million, $13 million and $29 million in the first, second, third and fourth quarters, respectively.

- Earnings for the fourth quarter of 2011 included a charge totaling $262 million, after-tax, as a result of the discontinuance of rate regulated accounting at EGNB. This item was recognized as an extraordinary item in the Company s 2011 U.S. GAAP consolidated financial statements.

- First quarter 2011 earnings reflected positive contributions from gas gathering assets purchased in the fourth quarter of 2010.

- In April and July of 2010, the Company completed Alberta Clipper and Southern Lights Pipeline, respectively, two of the largest projects in the Company s history, and commenced recording in-service earnings from those dates forward.

NON-GAAP RECONCILIATION

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
GAAP earnings as reported	**264**	364
Significant after-tax non-recurring or non-operating factors and variances:		
Liquids Pipelines		
Canadian Mainline - Line 9 tolling adjustment	**(6)**	-
Canadian Mainline - unrealized derivative fair value gains	**(27)**	-
Gas Distribution		
EGD - (colder)/warmer than normal weather	**24**	(11)
Gas Pipelines, Processing and Energy Services		
Aux Sable - unrealized derivative fair value (gains)/loss	**(7)**	6
Energy Services - unrealized derivative fair value loss	**154**	7
Sponsored Investments		
EEP - NGL trucking and marketing investigation costs	**1**	-
EEP - unrealized derivative fair value loss	**-**	3
EEP - leak insurance recoveries	**-**	(5)
EEP - lawsuit settlement	**-**	(1)
EEP - impact of unusual weather conditions	**-**	1
Corporate		
Noverco - equity earnings adjustment	**12**	-
Other Corporate - unrealized derivative fair value gains	**(10)**	(16)
Other Corporate - foreign tax recovery	**(29)**	-
Other Corporate - unrealized foreign exchange gains on translation of intercompany balances, net	**-**	(18)
Adjusted earnings	**376**	330

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
Common Shares - issued and outstanding (voting equity shares)	784,966,571
Stock Options - issued and outstanding (20,911,380 vested)	35,467,400

1 Outstanding share data information is provided as at May 2, 2012.

2 Non-voting equity shares.

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.

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

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

March 31, 2012

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars, except per share amounts)		
Revenues		
Commodity sales	**4,838**	4,737
Gas distribution sales	**767**	753
Transportation and other services	**1,022**	1,039
	6,627	6,529
Expenses		
Commodity costs	**4,661**	4,591
Gas distribution costs	**559**	555
Operating and administrative	**632**	508
Depreciation and amortization	**290**	277
Environmental costs, net of recoveries	**3**	(33)
	6,145	5,898
	482	631
Income from equity investments	**38**	55
Other income	**86**	80
Interest expense	**(217)**	(230)
	389	536
Income taxes *(Note 10)*	**(30)**	(103)
Earnings	**359**	433
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(80)**	(67)
Earnings attributable to Enbridge Inc.	**279**	366
Preference share dividends	**(15)**	(2)
Earnings attributable to Enbridge Inc. common shareholders	**264**	364
Earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.35**	0.49
Diluted earnings per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.34**	0.48

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars)		
Earnings	**359**	433
Other comprehensive income/(loss)		
Change in unrealized gain on cash flow hedges, net of tax	**160**	30
Change in unrealized gain on net investment hedges, net of tax	**9**	30
Reclassification to earnings of realized cash flow hedges, net of tax	**13**	(14)
Reclassification to earnings of unrealized cash flow hedges, net of tax	**2**	-
Other comprehensive loss from equity investees, net of tax	**(5)**	(4)
Overfunded pension adjustment, net of tax	**6**	4
Change in foreign currency translation adjustment	**(128)**	(169)
Other comprehensive income/(loss)	**57**	(123)
Comprehensive income	**416**	310
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(56)**	20
Comprehensive income attributable to Enbridge Inc.	**360**	330
Preference share dividends	**(15)**	(2)
Comprehensive income attributable to Enbridge Inc. common shareholders	**345**	328

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, **2012**	2011
Preference shares *(Note 6)*		
Balance at beginning of period	**1,056**	125
Shares issued	**832**	-
Balance at end of period	**1,888**	125
Common shares		
Balance at beginning of period	**3,969**	3,683
Dividend reinvestment and share purchase plan	**65**	64
Shares issued on exercise of stock options	**23**	19
Balance at end of period	**4,057**	3,766
Additional paid-in capital		
Balance at beginning of period	**242**	131
Stock-based compensation	**12**	8
Options exercised	**(4)**	(2)
Dilution gains and other	**6**	2
Issuance of treasury stock *(Note 8)*	**204**	-
Balance at end of period	**460**	139
Retained earnings		
Balance at beginning of period	**3,926**	3,993
Earnings attributable to Enbridge Inc.	**279**	366
Preference share dividends	**(15)**	(2)
Common share dividends declared	**(221)**	(188)
Dividends paid to reciprocal shareholder	**5**	5
Redemption value adjustment attributable to redeemable noncontrolling interests	**(52)**	(46)
Balance at end of period	**3,922**	4,128
Accumulated other comprehensive income/(loss) *(Note 7)*		
Balance at beginning of period	**(1,532)**	(1,027)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**81**	(35)
Balance at end of period	**(1,451)**	(1,062)
Reciprocal shareholding		
Balance at beginning of period	**(187)**	(154)
Issuance of treasury stock *(Note 8)*	**61**	-
Balance at end of period	**(126)**	(154)
Total Enbridge Inc. shareholders equity	**8,750**	6,942
Noncontrolling interests		
Balance at beginning of period	**3,141**	2,424
Earnings attributable to noncontrolling interests	**78**	69
Other comprehensive income/(loss) attributable to noncontrolling interests		
Change in realized and unrealized gains/(loss) on cash flow hedges, net of tax	**30**	(37)
Change in foreign currency translation adjustment	**(54)**	(51)
	(24)	(88)
Comprehensive income/(loss) attributable to noncontrolling interests	**54**	(19)
Contributions	**2**	47
Distributions	**(102)**	(82)
Other	**(8)**	2
Balance at end of period	**3,087**	2,372
Total equity	**11,837**	9,314
Dividends paid per common share	**0.2825**	0.2450

See accompanying notes to the unaudited consolidated financial statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31,	
	2012	2011
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**359**	433
Depreciation and amortization	**290**	277
Unrealized loss on derivative instruments	**201**	16
Cash distributions in excess of equity earnings	**58**	20
Deferred income taxes (recovery)/expense	**(23)**	78
Other	**20**	(4)
Change in regulatory assets and liabilities	**14**	31
Change in environmental liabilities, net of recoveries	**(2)**	(119)
Change in operating assets and liabilities	**(269)**	431
	648	1,163
Investing activities		
Additions to property, plant and equipment	**(877)**	(536)
Additions to intangible assets	**(48)**	(9)
Change in construction payable	**71**	(74)
Long-term investments	**(63)**	(21)
Affiliate loans, net	**2**	2
Acquisition *(Note 4)*	**(7)**	-
Change in restricted cash	**(6)**	(9)
	(928)	(647)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**(172)**	(134)
Net change in commercial paper and credit facility draws	**(220)**	(2)
Debenture and term note issues	**500**	-
Net change in Southern Lights project financing	**(5)**	(24)
Distributions to noncontrolling interests, net	**(100)**	(24)
Distributions to redeemable noncontrolling interests, net	**(12)**	(7)
Preference shares issued	**826**	-
Common shares issued	**17**	16
Preference share dividends	**(15)**	(2)
Common share dividends	**(156)**	(124)
	663	(301)
Effect of translation of foreign denominated cash and cash equivalents	**(12)**	(7)
Increase in cash and cash equivalents	**371**	208
Cash and cash equivalents at beginning of period	**723**	376
Cash and cash equivalents at end of period	**1,094**	584

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2012	December 31, 2011
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,094**	723
Restricted cash	**23**	17
Accounts receivable and other	**3,659**	4,011
Accounts receivable from affiliates	**18**	55
Inventory	**554**	823
	5,348	5,629
Property, plant and equipment, net	**29,550**	28,941
Long-term investments	**3,410**	3,160
Deferred amounts and other assets	**2,509**	2,667
Intangible assets	**741**	711
Goodwill	**437**	440
Deferred income taxes	**6**	29
	42,001	41,577
Liabilities and equity		
Current liabilities		
Bank indebtedness	**196**	102
Short-term borrowings	**282**	548
Accounts payable and other	**4,222**	4,764
Accounts payable from affiliates	**2**	48
Interest payable	**214**	185
Environmental liabilities	**129**	175
Current maturities of long-term debt	**552**	354
	5,597	6,176
Long-term debt	**19,189**	19,251
Other long-term liabilities	**2,100**	2,323
Deferred income taxes	**2,597**	2,572
	29,483	30,322
Commitments and contingencies *(Note 12)*		
Redeemable noncontrolling interests	**681**	640
Equity		
Share capital		
Preference shares *(Note 6)*	**1,888**	1,056
Common shares (785 and 781 outstanding at March 31, 2012 and December 31, 2011, respectively)	**4,057**	3,969
Additional paid-in capital	**460**	242
Retained earnings	**3,922**	3,926
Accumulated other comprehensive loss *(Note 7)*	**(1,451)**	(1,532)
Reciprocal shareholding *(Note 8)*	**(126)**	(187)
Total Enbridge Inc. shareholders equity	**8,750**	7,474
Noncontrolling interests	**3,087**	3,141
	11,837	10,615
	42,001	41,577

See accompanying notes to the unaudited consolidated financial statements.

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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 United States generally accepted accounting principles (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, 2011 prepared in accordance with U.S. GAAP and filed with Canadian and United States securities regulators on a voluntary basis (U.S. GAAP Consolidated Financial Statements). 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, 2012 and results of operations and cash flows for the three month periods ended March 31, 2012 and 2011. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company s U.S. GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011, except as described in Note 2, Changes in accounting policies. Amounts are stated in Canadian dollars unless otherwise noted.

The Company commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. As a Securities 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. The Company s 2011 Annual Report included consolidated financial statements and notes thereto for the year ended December 31, 2011 prepared in accordance with Part V Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants Handbook. The Company s U.S. GAAP Consolidated Financial Statements for the three years ended December 31, 2011 were prepared, and voluntarily filed with securities regulators in Canada and the United States, to facilitate users understanding of the transition to U.S. GAAP.

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. CHANGES IN ACCOUNTING POLICIES

REGULATION

Enbridge Gas New Brunswick

Based on amendments to the rate setting methodology outlined in a final rates and tariff regulation enacted by the Government of New Brunswick, Enbridge Gas New Brunswick (EGNB) no longer meets the criteria for rate regulated accounting. As a result, effective January 1, 2012, the Company discontinued rate regulated accounting for EGNB.

OTHER

Fair Value Measurement

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) 2011-04, which revised the existing guidance on the disclosure of fair value measurements under U.S. GAAP as part of the Financial Accounting Standard Board s joint project with the International Accounting Standards Board. Under the revised standard, the Company is required to provide additional disclosures about fair value measurements, including a description of the valuation methodologies used and information about the unobservable inputs and assumptions used in Level 3 fair value measurements, as well as the level in the fair value hierarchy of items that are not measured at fair value but whose fair value disclosure is required. As the adoption of this update impacted disclosure only, there was no impact to the Company s earnings or cash flows for the current or prior periods presented.

Statement of Comprehensive Income

Effective January 1, 2012, the Company adopted ASU 2011-05, which updates the existing guidance on comprehensive income, requiring presentation of earnings and other comprehensive income (OCI) either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of earnings and OCI. The adoption of this pronouncement did not affect the Company s presentation of comprehensive income and did not impact the Company s consolidated financial statements.

Goodwill Impairment

Effective January 1, 2012, the Company adopted ASU 2011-08 which is intended to reduce the overall costs and complexity of goodwill impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity is not required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, it is more likely than not its fair value is less than its carrying amount. Adoption of this standard does not change the current two-step goodwill impairment test.

3. SEGMENTED INFORMATION

Three months ended March 31, 2012	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**596**	**917**	**3,286**	**1,828**	**-**	**6,627**
Commodity and gas distribution costs	**-**	**(560)**	**(3,457)**	**(1,203)**	**-**	**(5,220)**
Operating and administrative	**(212)**	**(127)**	**(35)**	**(260)**	**2**	**(632)**
Depreciation and amortization	**(84)**	**(83)**	**(15)**	**(105)**	**(3)**	**(290)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**(3)**	**-**	**(3)**
	300	**147**	**(221)**	**257**	**(1)**	**482**
Income/(loss) from equity investments	**1**	**-**	**28**	**15**	**(6)**	**38**
Other income/(expense)	**4**	**(5)**	**13**	**15**	**59**	**86**
Interest expense	**(62)**	**(41)**	**(11)**	**(98)**	**(5)**	**(217)**
Income taxes recovery/(expense)	**(51)**	**(23)**	**81**	**(45)**	**8**	**(30)**
Earnings/(loss)	**192**	**78**	**(110)**	**144**	**55**	**359**
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	**191**	**78**	**(111)**	**66**	**40**	**264**
Additions to property, plant and equipment1	**370**	**79**	**149**	**268**	**11**	**877**

Three months ended March 31, 2011 *(millions of Canadian dollars)*	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
Revenues	459	943	2,912	2,215	-	6,529
Commodity and gas distribution costs	-	(555)	(2,852)	(1,739)	-	(5,146)
Operating and administrative	(150)	(120)	(27)	(208)	(3)	(508)
Depreciation and amortization	(81)	(79)	(19)	(96)	(2)	(277)
Environmental costs, net of recoveries	-	-	-	33	-	33
	228	189	14	205	(5)	631
Income from equity investments	-	-	27	16	12	55
Other income/(expense)	-	(5)	10	21	54	80
Interest expense	(64)	(44)	(15)	(85)	(22)	(230)
Income taxes recovery/(expense)	(28)	(38)	(9)	(36)	8	(103)
Earnings	136	102	27	121	47	433
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	-	-	(1)	(66)	-	(67)
Preference share dividends	-	-	-	-	(2)	(2)
Earnings attributable to Enbridge Inc. common shareholders	136	102	26	55	45	364
Additions to property, plant and equipment1	188	64	72	209	4	537

1 Includes allowance for equity funds used during construction.

TOTAL ASSETS

(millions of Canadian dollars)	**March 31, 2012**	December 31, 2011
Liquids Pipelines	**14,011**	12,470
Gas Distribution	**6,586**	7,189
Gas Pipelines, Processing and Energy Services	**4,950**	4,468
Sponsored Investments	**13,070**	13,453
Corporate	**3,384**	3,997
	42,001	41,577

4. ACQUISITION

SILVER STATE NORTH SOLAR PROJECT

On March 22, 2012, Enbridge acquired a 100% interest in the Silver State North Solar Project (Silver State), a solar farm located in Nevada, USA for cash consideration of $7 million (US$7 million) and an additional $183 million (US$183 million), included in Accounts payable and other, to be paid upon commencement of commercial operation, which is anticipated in May 2012.

Silver State was acquired in order to expand the Company s alternative energy business. No earnings were recognized in the three months ended March 31, 2012, or in any prior period, as the solar project has not commenced operation. As at March 31, 2012, the purchase price allocation was not complete as the Company has not completed its valuation of the acquired assets.

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5. CREDIT FACILITIES

March 31, 2012	Maturity Dates[2]	Total Facilities	Credit Facility Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines	**2013**	**300**	**25**	**275**
Gas Distribution	**2012-2013**	**717**	**290**	**427**
Sponsored Investments	**2013-2016**	**2,498**	**737**	**1,761**
Corporate	**2013-2016**	**6,473**	**2,394**	**4,079**
		9,988	**3,446**	**6,542**
Southern Lights project financing[1]	**2013-2014**	**1,505**	**1,442**	**63**
Total credit facilities		**11,493**	**4,888**	**6,605**

1 Total facilities inclusive of $60 million for debt service reserve letters of credit.
2 Total facilities include $30 million in demand facilities with no maturity date.
3 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

Credit facilities carry a weighted average standby fee of 0.16% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2012 to 2016.

Commercial paper and credit facility draws, net of short-term borrowings, of $3,122 million (2011 - $3,359 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

6. SHARE CAPITAL

PREFERENCE SHARES

	March 31, 2012		December 31, 2011	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Preference shares, Series A	**5**	**125**	5	125
Preference shares, Series B	**20**	**490**	20	490
Preference shares, Series D	**18**	**441**	18	441
Preference shares, Series F[1]	**20**	**490**	-	-
Preference shares, Series H[2]	**14**	**342**	-	-
Balance at end of period		**1,888**		1,056

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

2 *Gross proceeds - $350 million; net issuance costs - $8 million.*

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 F5	4.0%	1.000	25	June 1, 2018	Series G
Preference shares, Series H6	4.0%	1.000	25	September 1, 2018	Series I

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

2 The Company may at its option, redeem all or a portion of the outstanding preference shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.
3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on the Conversion Option Date and every fifth anniversary thereafter.
4 Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.40% (Series C), 2.37% (Series E), 2.51% (Series G) or 2.12% (Series I)).
5 A cash dividend of $0.3699 per share will be paid on June 1, 2012 to Series F shareholders of record as of May 15, 2012. The regular quarterly dividend of $0.25 per share will begin in the third quarter of 2012.
6 A cash dividend of $0.4247 per share will be paid on September 1, 2012 to Series H shareholders. The regular quarterly dividend of $0.25 per share will begin in the fourth quarter of 2012.

Subsequent to March 31, 2012, the Company issued eight million Series J Preference Shares for gross proceeds of US$200 million. The 4.0% Cumulative Redeemable Preference Shares, Series J are entitled to the same dividends, and similar redemption and conversion terms as the Series B, Series D, Series F and Series H Preference Shares, except any cash payments are to be made in United States dollars. Redemption of Series J Preference Shares by the Company or conversion by holders into Cumulative Redeemable Preference Shares, Series K can occur on June 1, 2017 and on June 1 of every fifth year thereafter. The holders of Series K Preference Shares will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to US$25 multiplied by the number of days in the quarter divided by 365 and multiplying that product by the sum of the then 90-day United States Government Treasury bill rate plus 3.05%.

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 26 million (2011 - 23 million), resulting from the Company s reciprocal investment in Noverco Inc. (Noverco).

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

	Three months ended March 31,	
	2012	2011
(number of shares in millions)		
Weighted average shares outstanding	**757**	750
Effect of dilutive options	**12**	8
Diluted weighted average shares outstanding	**769**	758

For the three months ended March 31, 2012, 5,759,150 anti-dilutive stock options (2011 - 4,913,200) with a weighted average exercise price of $38.32 (2011 - $28.78) were excluded from the diluted earnings per share calculation.

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

	Cash Flow Hedges	Net Investment Hedges	Equity Investees	Pension Actuarial Gain/Loss Adjustment	Cumulative Translation Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2011	(66)	480	(11)	(142)	(1,288)	(1,027)
Changes during the period	63	36	(4)	5	(117)	(17)
Tax impact	(11)	(6)	-	(1)	-	(18)
	52	30	(4)	4	(117)	(35)
Balance at March 31, 2011	(14)	510	(15)	(138)	(1,405)	(1,062)
Balance at January 1, 2012	(476)	461	(28)	(286)	(1,203)	(1,532)
Changes during the period	**193**	10	**-**	**7**	**(74)**	**136**
Tax impact	**(48)**	(1)	**(5)**	**(1)**	**-**	**(55)**
	145	9	**(5)**	**6**	**(74)**	**81**
Balance at March 31, 2012	**(331)**	470	**(33)**	**(280)**	**(1,277)**	**(1,451)**

8. RECIPROCAL SHAREHOLDING

At December 31, 2011, Noverco owned an approximate 8.9% reciprocal shareholding in the common shares of the Company. On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering, thereby reducing the Company s reciprocal shareholding to 6.0%. Both the Company s equity investment in Noverco, included in Long-term investments, and Equity have increased by $265 million, net of tax, as a result of this transaction.

9. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

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

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

Foreign Exchange Risk

The Company s earnings, cash flows, and OCI are subject to foreign exchange rate variability, primarily arising from its United States dollar denominated investments and subsidiaries, and certain revenues denominated in United States dollars. 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 volatility of short-term interest rates on interest expense through 2016 at an average swap rate of 2.32%.

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

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

Commodity Price Risk

The Company s earnings and cash flows are exposed to changes in commodity prices as a result of ownership interest in certain assets and investments, as well as through the activities of its energy services subsidiaries. These commodities include natural gas, power, crude oil 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.

The Company has implemented a program to mitigate the volatility from fractionation spreads (natural gas/NGL) that impact earnings from its ownership in the Aux Sable natural gas processing plant and the gathering and processing business held by Enbridge Energy Partners, L.P. (EEP).

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in the Company s share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, 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, 2012 or December 31, 2011.

March 31, 2012	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments1
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**4**	**15**	**218**	**237**	**-**	**237**
Interest rate contracts	**-**	**-**	**10**	**10**	**(3)**	**7**
Commodity contracts	**11**	**-**	**241**	**252**	**(22)**	**230**
Other contracts	**2**	**-**	**8**	**10**	**-**	**10**
	17	**15**	**477**	**509**	**(25)**	**484**
Deferred amounts and other						
Foreign exchange contracts	**15**	**82**	**203**	**300**	**-**	**300**
Interest rate contracts	**6**	**-**	**17**	**23**	**(3)**	**20**
Commodity contracts	**10**	**-**	**108**	**118**	**(13)**	**105**
Other contracts	**3**	**-**	**3**	**6**	**-**	**6**
	34	**82**	**331**	**447**	**(16)**	**431**
Accounts payable and other						
Foreign exchange contracts	**(5)**	**-**	**(140)**	**(145)**	**-**	**(145)**
Interest rate contracts	**(402)**	**-**	**(5)**	**(407)**	**3**	**(404)**
Commodity contracts	**(29)**	**-**	**(257)**	**(286)**	**22**	**(264)**
	(436)	**-**	**(402)**	**(838)**	**25**	**(813)**
Other long-term liabilities						
Foreign exchange contracts	**(40)**	**(5)**	**(12)**	**(57)**	**-**	**(57)**
Interest rate contracts	**(262)**	**-**	**(15)**	**(277)**	**3**	**(274)**
Commodity contracts	**(38)**	**-**	**(105)**	**(143)**	**13**	**(130)**
	(340)	**(5)**	**(132)**	**(477)**	**16**	**(461)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(26)**	**92**	**269**	**335**	**-**	**335**
Interest rate contracts	**(658)**	**-**	**7**	**(651)**	**-**	**(651)**
Commodity contracts	**(46)**	**-**	**(13)**	**(59)**	**-**	**(59)**
Other contracts	**5**	**-**	**11**	**16**	**-**	**16**
	(725)	**92**	**274**	**(359)**	**-**	**(359)**

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

1 As presented in the Consolidated Statements of Financial Position.

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

March 31, 2012	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**169**	**55**	**468**	**25**	**25**	**420**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,425**	**1,865**	**2,182**	**2,583**	**2,039**	**182**
Foreign exchange contracts - Euro dollar forwards - purchase *(millions of Euros)*	**1**	**-**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**2,444**	**3,357**	**2,914**	**2,766**	**2,553**	**224**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**2,650**	**2,000**	**1,650**	**750**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**37**	**27**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**14**	**70**	**15**	**14**	**1**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**3**	**44**	**32**	**22**	**18**	**23**
Commodity contracts - NGL *(millions of barrels)*	**7**	**1**	**-**	**-**	**-**	**-**

Commodity contracts - power *(megawatts per hour (MWH))*	**38**	**38**	**40**	**48**	**63**	**58**

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December 31, 2011	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	58	287	468	25	25	418
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	2,017	1,865	2,182	2,583	2,039	180
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	3,227	3,237	2,787	2,641	2,428	215
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	2,650	2,000	1,650	750	-	-
Equity contracts *(millions of Canadian dollars)*	36	26	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	20	59	1	1	1	-
Commodity contracts - crude oil *(millions of barrels)*	11	26	17	8	7	10
Commodity contracts - NGL *(millions of barrels)*	4	1	-	-	-	-
Commodity contracts - power *(MWH)*	40	28	40	48	63	58

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.

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Amount of unrealized gain/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**19**	(19)
Interest rate contracts	**180**	78
Commodity contracts	**(8)**	(56)
Other contracts	**(1)**	1
Net investment hedges		
Foreign exchange contracts	**3**	20
	193	24
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Cash flow hedges		
Interest rate contracts[1]	**14**	4
Commodity contracts[2]	**2**	(9)
	16	(5)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Cash flow hedges		
Commodity contracts[2]	**(2)**	1
	(2)	1

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 $182 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 foreign exchange rates, interest rates and commodity prices when derivative contracts currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 57 months at March 31, 2012.

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,	
	2012	2011
(millions of Canadian dollars)		
Foreign exchange contracts1	**15**	22
Interest rate contracts2	**(2)**	-
Commodity contracts3	**(203)**	(34)
Other contracts4	**-**	(2)
Total unrealized derivative fair value loss	**(190)**	(14)

1 *Reported within Transportation and other services revenue 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 *(Note 12)*, 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, 2012. 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 Securities Dealers Association (ISDA) agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company s credit risk exposure on derivative asset positions outstanding with these counterparites in these particular circumstances.

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

	March 31, 2012	December 31, 2011
(millions of Canadian dollars)		
Canadian financial institutions	**340**	431
United States financial institutions	**174**	287
European financial institutions	**211**	257
Other[1]	**195**	112
	920	1,087

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

As at March 31, 2012, the Company has provided letters of credit totaling $148 million in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. The Company holds no cash collateral on asset exposures at March 31, 2012 or December 31, 2011.

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, which is 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. Also, the Company 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 is supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

The Company categorizes its financial instruments into one of three levels depending on the observability of the inputs employed in the measurement.

Level 1

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

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 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 include long-dated derivative power contracts and NGL and natural gas contracts in the Gas Pipelines, Processing and Energy Services and Sponsored Investments segments. The Company 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 pricing models for options. Depending on the type of derivative and nature of the underlying risk, the Company uses observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, the Company considers its own credit default swap spread, as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

Fair Value of Derivatives

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

March 31, 2012	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	**-**	**237**	**-**	**237**	**-**	**237**
Interest rate contracts	**-**	**10**	**-**	**10**	**(3)**	**7**
Commodity contracts	**3**	**100**	**149**	**252**	**(22)**	**230**
Other contracts	**-**	**10**	**-**	**10**	**-**	**10**
	3	**357**	**149**	**509**	**(25)**	**484**
Long-term derivative assets						
Foreign exchange contracts	**-**	**300**	**-**	**300**	**-**	**300**
Interest rate contracts	**-**	**23**	**-**	**23**	**(3)**	**20**
Commodity contracts	**-**	**65**	**53**	**118**	**(13)**	**105**
Other contracts	**-**	**6**	**-**	**6**	**-**	**6**
	-	**394**	**53**	**447**	**(16)**	**431**
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	**-**	**(145)**	**-**	**(145)**	**-**	**(145)**
Interest rate contracts	**-**	**(407)**	**-**	**(407)**	**3**	**(404)**
Commodity contracts	**-**	**(181)**	**(105)**	**(286)**	**22**	**(264)**
	-	**(733)**	**(105)**	**(838)**	**25**	**(813)**
Long-term derivative liabilities						
Foreign exchange contracts	**-**	**(57)**	**-**	**(57)**	**-**	**(57)**
Interest rate contracts	**-**	**(277)**	**-**	**(277)**	**3**	**(274)**
Commodity contracts	**-**	**(93)**	**(50)**	**(143)**	**13**	**(130)**
	-	**(427)**	**(50)**	**(477)**	**16**	**(461)**
Total net financial asset/(liability)						
Foreign exchange contracts	**-**	**335**	**-**	**335**	**-**	**335**
Interest rate contracts	**-**	**(651)**	**-**	**(651)**	**-**	**(651)**
Commodity contracts	**3**	**(109)**	**47**	**(59)**	**-**	**(59)**
Other contracts	**-**	**16**	**-**	**16**	**-**	**16**
	3	**(409)**	**47**	**(359)**	**-**	**(359)**

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

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

	Fair value at March 31, 2012 *(millions of Canadian dollars)*	**Unobservable Input**	**Minimum Price**	**Maximum Price**	**Weighted Average Price**	
Commodity Contracts - Financial1						
Natural Gas	(4)	Forward Gas Price	2.05	3.93	2.57	$/mmbtu3
Crude	2	Forward Crude Price	70.14	110.10	100.70	$/barrel
NGL	(10)	Forward NGL Price	0.19	2.43	1.04	$/gallon
Power	12	Forward Power Price	48.75	88.37	74.60	$/MWH
Commodity Contracts - Physical1						
Natural Gas	19	Forward Gas Price	2.04	4.41	3.95	$/mmbtu3
Crude	9	Forward Crude Price	77.99	119.91	102.26	$/barrel
NGL	9	Forward NGL Price	0.50	2.64	1.68	$/gallon
Power	(2)	Forward Power Price	23.04	31.61	32.07	$/MWH
Commodity Options2						
Natural Gas	2	Option Volatility	26%	36%	31%	
NGL	10	Option Volatility	28%	62%	44%	

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 would result in significantly different fair values for long positions, with offsetting impacts to short positions. 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 instruments classified as Level 3 in the fair value hierarchy were as follows:

	Three months ended, March 31,	
	2012	2011
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**32**	(24)
Total gains/(losses), unrealized		
Included in earnings1	**18**	(37)
Included in OCI	**2**	(28)

Settlements	**(5)**	12
Level 3 net derivative asset/(liability) at end of period	**47**	(77)

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

The Company s policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at March 31, 2012 or 2011.

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. At March 31, 2012 and

December 31, 2011, all equity investments of this nature held by the Company are recognized at cost with a carrying value of $47 million at March 31, 2012 (December 31, 2011 - $56 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $580 million at March 31, 2012 (December 31, 2011 - $285 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 4.34% to 4.40%. At March 31, 2012, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2011 - $580 million).

At March 31, 2012, the Company s long-term debt had a carrying value of $19,741 million (December 31, 2011 - $19,605 million) and a fair value of $22,288 million (December 31, 2011 - $22,620 million).

10. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2012 was 9.6% (2011 - 22.0%). Significant variances between the effective income tax rate and the weighted average Canadian statutory income tax rate were as follows:

	Three months ended March 31,	
	2012	2011
Canadian weighted average statutory tax rate	**25.7%**	25.4%
Foreign rate differential[1]	**(13.9%)**	-
Other	**(2.2%)**	(3.4%)
	9.6%	22.0%

1 *The effective income tax rate decreased significantly from the prior year substantially as a result of losses arising on certain risk management activities in the Company s United States operations. The benefit was due to the higher United States income tax rate over the Canadian weighted average statutory tax rate.*

11. 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 (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees. The Company also provides other postretirement benefits (OPEB) for qualifying retired employees. Costs related to the period are presented below.

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NET BENEFIT COSTS RECOGNIZED

	Three months ended March 31,	
	2012	2011
(millions of Canadian dollars)		
Benefits earned during the period	**19**	17
Interest cost on projected benefit obligations	**13**	21
Expected return on plan assets	**(14)**	(24)
Amortization of prior service costs	**-**	1
Amortization of actuarial loss	**6**	6
Net benefit costs[1]	**24**	21

1 *Included in net benefit costs are costs related to OPEB of $3 million (2011 - $3 million).*

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Three months ended March 31,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Contributions paid	**15**	15	**1**	1
Contributions expected to be paid in the next nine months	**91**		**10**	
Total contributions expected to be paid in the year	**106**		**11**	

12. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,935 million which are expected to be paid within the next five years.

EEP LAKEHEAD SYSTEM LINE 6A AND 6B CRUDE OIL RELEASES

Enbridge holds an approximate 23% combined direct and indirect ownership interest in EEP. Under U.S. GAAP, Enbridge consolidates EEP and its earnings, net of noncontrolling interests, are reflected within the Sponsored Investments segment.

Line 6B Crude Oil Release

EEP continues to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with extended submerged oil recovery operations, including reassessment, remediation and restoration of the area and air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

The total cost estimate for this incident remains at approximately US$765 million ($129 million after-tax attributable to Enbridge) at March 31, 2012 based on a review of costs and commitments incurred coupled with the evaluation of additional information regarding requirements for environmental restoration and remediation. Expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at March 31, 2012. The estimates do not include amounts capitalized or any fines, penalties or claims associated with the release that may later become evident and are before insurance recoveries. Despite the efforts EEP has made to ensure the reasonableness of its estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. There continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at US$48 million ($7 million after-tax attributable to Enbridge), before any third party or insurance recoveries and excluding fines and penalties.

EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP s remediation spending through March 31, 2012, Enbridge and its affiliates have exceeded the limits of its 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 insurance 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. At March 31, 2012, EEP had collected total insurance recoveries of US$335 million ($50 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to EEP s insurance policies during the period that EEP deems realization of the claim for recovery to be probable. In the first quarter of 2011, EEP recognized insurance recoveries of US$35 million ($5 million after-tax attributable to Enbridge) for claims that it filed while no such recoveries were recognized during the first quarter of 2012.

Enbridge s current comprehensive insurance program, expiring April 30, 2012, has a current liability aggregate limit of US$575 million, including pollution liability. Enbridge will renew its liability insurance and expects to increase the aggregate limit of coverage effective May 1, 2012 through April 30, 2013.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. Based on the current status of these cases, these actions are not expected to be material. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at March 31, 2012. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are currently operating under an agreed interim order.

TAX MATTERS

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

OTHER 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.