ENBRIDGE INC
Form 6-K
August 05, 2011

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 August 5, 2011

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. 333-152607 AND 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 AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.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 August 5, 2011.

- Interim Report to Shareholders for the six months ended June 30, 2011.

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: August 5, 2011	By: /s/ Alison T. Love Alison T. Love Vice President, Corporate Secretary & Chief Compliance Officer

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NEWS RELEASE

Enbridge reports second quarter adjusted earnings of $260 million or $0.35 per common share

HIGHLIGHTS

(all financial figures are unaudited and in Canadian dollars)

- Second quarter earnings were $259 million; six month earnings were $652 million, or $0.87 per common share

- Second quarter and six month adjusted earnings increased to $260 million, or $0.35 per common share, and $594 million, or $0.79 per common share, respectively

- 10-year Competitive Toll Settlement (CTS) on crude oil mainline system approved in June 2011

- Two-for-one stock split approved by shareholders became effective May 25, 2011

CALGARY, ALBERTA, August 5, 2011 Enbridge Inc. (TSX:ENB) (NYSE:ENB) During the second quarter we continued to run slightly ahead of our original expectations and the outlook for the full year is now trending toward the upper half of our adjusted earnings per share guidance range of $1.38 to $1.48, said Patrick D. Daniel, President and Chief Executive Officer.

In June, the National Energy Board (NEB) approved the 10-year CTS agreement, which took effect on July 1, 2011. The CTS covers the local tolls to be charged for service on the Canadian portion of the mainline system as well as provides for an International Joint Tariff (IJT) for United States deliveries originating in Canada.

We are pleased with the decision of the NEB and look forward to implementing this long-term agreement to the mutual benefit of Enbridge and our shippers, said Mr. Daniel. The CTS will provide a stable and competitive long-term toll for crude volumes received into the Canadian Mainline System and delivered to points both within Canada and the U.S. This agreement will enable us to continue to deliver reliable earnings and dividends with attractive returns under conservative throughput assumptions, further reinforcing our confidence in our ability to deliver a 10% average annual growth rate in earnings per share through the middle of this decade.

The CTS will also facilitate market extensions that can be accessed from our mainline system through new or existing downstream pipelines, said Mr. Daniel. In fact, we have already found it to be a catalyst in advancing business development opportunities to extend our traditional market reach.

Over the second quarter, Enbridge continued to advance a number of growth projects including existing Liquids Pipelines projects in the Oil Sands region. Construction is continuing on projects including the Christina Lake Lateral, Woodland Pipeline, Wood Buffalo Pipeline, and the Waupisoo Pipeline and Athabasca Pipeline expansion.

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.

The regulatory review of the Northern Gateway Project also took a step forward in the second quarter with the release by the Joint Review Panel (JRP) of the Hearing Order setting out the schedule for the hearing process.   Northern Gateway will bring Canada s energy resources to the growing economies of the Pacific basin, while delivering sustainable local and regional prosperity to northern BC and Alberta and national economic benefits for all Canadians,   said Mr. Daniel.   We re pleased with the scope of the public hearings, which clearly meets the widely expressed desire for a full and open review of the Project. The JRP will test the merits of our proposal and hold Enbridge to the highest standards. We have confidence that it will render a decision that is, and will be seen to be, in the best interests of Canada.

In Gas Pipelines, Processing and Energy Services, Enbridge announced the acquisition by an affiliate of Aux Sable of the Stanley Condensate Recovery Plant and the Prairie Rose Pipeline, key assets located in the Bakken area. The Prairie Rose Pipeline connects the Stanley Gas Plant to the Alliance Pipeline, which delivers high energy content gas to Aux Sable s Channahon, Illinois Plant for processing. Enbridge s proportionate share of the $185 million acquisition reflected its 42.7% interest in Aux Sable.

  As we enter the latter half of 2011, Enbridge remains confident of sustained strong performance and steady growth across all of our business segments, enabling us to continue to deliver superior results to our shareholders,   concluded Mr. Daniel.

SECOND QUARTER 2011 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/investor.

- On July 1, 2011, Sable NGL LLC, an affiliate of Aux Sable, acquired the Stanley Condensate Recovery Plant and the Prairie Rose Pipeline for US$0.2 billion. The Stanley Plant removes condensate and will have a capacity of 80 million cubic feet per day (MMcf/d). The 12-inch diameter, 134-kilometre (83-mile) Prairie Rose Pipeline, with an estimated capacity of 110 MMcf/d connects the Stanley Plant to the Alliance Pipeline, which then delivers high energy content gas to Aux Sable s Channahan, Illinois plant for processing. Enbridge has a 42.7% equity interest in both Aux Sable and Sable NGL LLC and a 50% interest in Alliance Pipeline.

- Enbridge s investment of $144 million to acquire an additional interest in Noverco Inc. (Noverco) from Laurentides Investissements (SAS), a subsidiary of GDF SUEZ, announced on February 3, 2011, was completed on June 30, 2011. Trencap, a partnership controlled and managed by the Caisse de Depot et Placement du Quebec, acquired Laurentides Investissements remaining 10.8% interest in Noverco; Enbridge and Trencap are now the sole shareholders of Noverco. Noverco is a holding company that owns 71% of the Gaz Metro Limited Partnership which owns gas distribution and gas pipeline assets in the province of Quebec and gas and electric power distribution and transmission assets in the State of Vermont.

- On June 24, 2011, the NEB approved the 10-year CTS agreement reached between Enbridge and shippers on its crude oil mainline system. The CTS took effect on July 1, 2011. The CTS covers local tolls to be charged for service on the Canadian Mainline and supersedes all existing toll agreements on the Canadian Mainline during the term of the CTS. Under the terms of the CTS, the initial Canadian local toll will be based on the 2011 Incentive Tolling Settlement (ITS) recently approved by the NEB. The Canadian local toll will then be adjusted by 75% of the Canada Gross Domestic Product at Market Price Index for each of the remaining nine years of the settlement. Local tolls for service on the Lakehead System (the portion of the mainline in the United States that is owned by the Company s affiliate Enbridge Energy Partners, L.P. (EEP)) will not be affected by the CTS and will continue to be established by EEP s existing toll agreements. The CTS also provides for an IJT for crude oil shipments originating in Canada on the Canadian Mainline and delivered in the United States off the Lakehead System and into Eastern Canada. The IJT is designed to provide mainline shippers with a stable and competitive long-term toll, preserving and enhancing throughput on both the Canadian Mainline and Lakehead System. With NEB approval of the CTS, shippers who initiated the Alberta Clipper hearing request with the NEB have formally withdrawn their complaints and the hearing proceedings were terminated on July 7, 2011.

- On May 11, 2011, shareholders approved a two-for-one stock split at the Company s Annual and Special Meeting of Shareholders. Effective May 25, 2011, the number of outstanding shares doubled from approximately 387 million to approximately 774 million.

• On May 9, 2011, Enbridge reported a crude oil release from a pipeline on its Norman Wells System approximately 50 kilometres south of the community of Wrigley, NWT. On May 20, 2011, Enbridge returned the Norman Wells line to service after completing the necessary repairs. Based on current estimates provided by the third party experts on site, Enbridge anticipates the release volume to be approximately 1,500 barrels. The Norman Wells pipeline is a 12-inch, 39,400 bpd line transporting sweet crude oil and stretches 869 kilometres (540 miles) from Norman Wells, NWT to Zama, AB.

• On May 4, 2011, Enbridge Income Fund Holdings Inc. (ENF) and Enbridge Income Fund (the Fund) announced receipt of a proposal from Enbridge pursuant to which Enbridge would transfer three renewable energy assets to the Fund. The proposal contemplates that the Ontario Wind, Sarnia Solar and Talbot Wind energy projects would be transferred for an aggregate price of $1.3 billion, to be paid in part by the issuance of additional ordinary trust units of the Fund (Units) to both ENF and Enbridge on a pro rata basis in accordance with their present holdings in the Fund. Under the proposal, Enbridge has agreed to provide bridge debt financing to the Fund for the balance of the price. Enbridge would also grant an option to ENF to acquire some or all of the Units for which Enbridge would be entitled to subscribe. The proposed transfer is subject to all necessary approvals, including approval by the Boards of ENF and the Fund and the minority shareholders of ENF, as well as regulatory approval. ENF and the Fund have formed a joint special committee comprised of independent trustees and directors to review the proposal and make recommendations to the respective boards of the Fund and ENF. If approved and completed, the transfer would further reinforce Enbridge s financial capacity to undertake attractive investment opportunities under development.

DIVIDEND DECLARATION

On August 4, 2011, the Enbridge Board of Directors declared quarterly dividends of $0.245 per common share on a post-split basis and $0.34375 per Series A Preferred Share. Both dividends are payable on September 1, 2011 to shareholders of record on August 15, 2011. On May 11, 2011, the Company s shareholders approved a stock split with a record date of May 25, 2011.

CONFERENCE CALL

Enbridge will hold a conference call on Friday, August 5, 2011 at 9:00 a.m. Eastern time (7:00 a.m. Mountain time) to discuss the second quarter 2011 results. Analysts, members of the media and other interested parties can access the call at +617-597-5344 or toll-free at 1-866-383-8119 using the access code of 64733884. The call will be audio webcast live at www.enbridge.com/InvestorRelations.aspx. 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 85834972) will be available until August 12, 2011.

The conference call will begin with a presentation by the Company s Chief Executive Officer and Chief Financial Officer followed by a question and answer period for investment analysts. A question and answer period for members of the media will 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 growing involvement in the natural gas transmission and midstream businesses, and is expanding its interests in renewable and green energy technologies including wind and solar energy, hybrid fuel cells and carbon dioxide sequestration. 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 approximately 6,400 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

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; prices of crude oil, natural gas and natural gas liquids; 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 natural gas liquids, 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 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 Canadian generally accepted accounting principles (Canadian GAAP) and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers.

Enbridge Contacts:

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HIGHLIGHTS

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(unaudited; millions of Canadian dollars, except per share amounts)				
Earnings Attributable to Common Shareholders				
Liquids Pipelines	**197**	133	**333**	267
Gas Distribution	**41**	20	**144**	100
Gas Pipelines, Processing and Energy Services	**34**	46	**85**	70
Sponsored Investments	**63**	57	**122**	109
Corporate	**(76)**	(118)	**(32)**	(66)
	259	138	**652**	480
Earnings per Common Share	**0.35**	0.19	**0.87**	0.65
Diluted Earnings per Common Share	**0.34**	0.18	**0.86**	0.64
Adjusted Earnings[1]				
Liquids Pipelines	**124**	133	**260**	267
Gas Distribution	**39**	30	**131**	118
Gas Pipelines, Processing and Energy Services	**44**	22	**83**	61
Sponsored Investments	**55**	51	**112**	102
Corporate	**(2)**	(4)	**8**	2
	260	232	**594**	550
Adjusted Earnings per Common Share	**0.35**	0.31	**0.79**	0.75
Cash Flow Data				
Cash provided by operating activities	**575**	511	**1,532**	1,157
Cash used in investing activities	**(622)**	(558)	**(1,087)**	(1,187)
Cash provided by/(used in) financing activities	**-**	23	**(378)**	107
Dividends				
Common share dividends declared	**190**	161	**378**	322
Dividends paid per common share	**0.2450**	0.2125	**0.4900**	0.4250
Shares Outstanding *(millions)*				
Weighted average common shares outstanding	**750**	739	**748**	737
Diluted weighted average common shares outstanding	**760**	747	**758**	745
Operating Data				
Liquids Pipelines - Average Deliveries *(thousands of barrels per day)*				
Canadian Mainline[2]	**2,070**	2,210	**2,193**	2,132
Regional Oil Sands System[3]	**285**	293	**307**	265
Spearhead Pipeline	**57**	161	**108**	137
Olympic Pipeline	**265**	285	**263**	272
Gas Distribution - Enbridge Gas Distribution				
Volumes *(billions of cubic feet)*	**75**	63	**268**	232
Number of active customers *(thousands)*[4]	**1,971**	1,936	**1,971**	1,936
Heating degree days[5]				
Actual	**485**	346	**2,451**	2,072
Forecast based on normal weather	**495**	490	**2,297**	2,253
Gas Pipelines, Processing and Energy Services - Average				
Throughput Volume *(millions of cubic feet per day)*				
Alliance Pipeline US	**1,519**	1,582	**1,601**	1,631
Vector Pipeline	**1,395**	1,353	**1,572**	1,435
Enbridge Offshore Pipelines	**1,732**	1,949	**1,741**	1,976

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1 *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.*

2 *Canadian Mainline includes deliveries in Western Canada and to the Lakehead System at the United States border as well as Line 8 and Line 9 in Eastern Canada.*

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

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

5 *Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in Enbridge Gas Distribution 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

June 30, 2011

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2011

This Management s Discussion and Analysis (MD&A) dated August 4, 2011 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 and six months ended June 30, 2011, which are prepared in accordance with Part V - Pre-changeover Accounting Standards of the Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company s Annual Report for the year ended December 31, 2010. 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 and on the Company s website at www.enbridge.com.

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.

CONSOLIDATED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**197**	133	**333**	267
Gas Distribution	**41**	20	**144**	100
Gas Pipelines, Processing and Energy Services	**34**	46	**85**	70
Sponsored Investments	**63**	57	**122**	109
Corporate	**(76)**	(118)	**(32)**	(66)
Earnings Attributable to Common Shareholders	**259**	138	**652**	480
Earnings per Common Share[1]	**0.35**	0.19	**0.87**	0.65
Diluted Earnings per Common Share[1]	**0.34**	0.18	**0.86**	0.64

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

Earnings attributable to common shareholders were $259 million for the three months ended June 30, 2011, or $0.35 per common share, compared with $138 million, or $0.19 per common share, for the three months ended June 30, 2010. This increase primarily reflected the recognition of unrealized fair value gains on financial derivatives used to manage risks inherent within the Competitive Toll Settlement (CTS), increased earnings from Enbridge Gas Distribution (EGD) due to favourable operating performance and the impact of colder weather, recognition of proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior periods, as well as lower net unrealized fair value losses on financial derivatives used to risk manage commodity price and foreign exchange rate fluctuations. The Company s Energy Services business also performed strongly during the second quarter of

2011, whereas the Company continues to experience lower volumes, and therefore lower earnings contributions, from its Enbridge Offshore Pipelines (Offshore) assets.

Earnings attributable to common shareholders were $652 million for the six months ended June 30, 2011, or $0.87 per common share, compared with $480 million, or $0.65 per common share, for the six months ended June 30, 2010. This increase primarily reflected the recognition of net unrealized fair value gains on financial derivatives compared with net unrealized fair value losses recognized in 2010, increased earnings from EGD due to favourable operating performance and the impact of colder weather as well as the recognition of proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior periods.

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 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; prices of crude oil, natural gas and natural gas liquids; 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 natural gas liquids, 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

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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 Canadian GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**124**	133	**260**	267
Gas Distribution	**39**	30	**131**	118
Gas Pipelines, Processing and Energy Services	**44**	22	**83**	61
Sponsored Investments	**55**	51	**112**	102
Corporate	**(2)**	(4)	**8**	2
Adjusted Earnings	**260**	232	**594**	550
Adjusted Earnings per Common Share[1]	**0.35**	0.31	**0.79**	0.75

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

Adjusted earnings were $260 million, or $0.35 per common share, for the three months ended June 30, 2011 compared with $232 million, or $0.31 per common share, for the three months ended June 30, 2010. Adjusted earnings were $594 million, or $0.79 per common share, for the six months ended June 30, 2011 compared with $550 million, or $0.75 per common share, for the six months ended June 30, 2010.

The following factors impacted the increase in adjusted earnings for both the three and six months ended June 30, 2011 compared with 2010.

- Within Liquids Pipelines, stronger contributions from the Canadian Mainline and the Regional Oil Sands System.

- Continued positive performance at EGD reflecting favourable operating performance under the current Incentive Regulation term.

- Within Gas Pipelines, Processing and Energy Services, increased earnings from stronger fractionation margins at Aux Sable, improved margin opportunities in crude oil marketing and the positive contribution from newly completed green energy facilities, offset by weak results from Offshore assets.

- Higher earnings for Sponsored Investments as a result of increased earnings from Alberta Clipper entering service in April 2010 as well as an increased contribution from Enbridge Income Fund (the Fund).

RECENT DEVELOPMENTS

LIQUIDS PIPELINES

Competitive Toll Settlement

On June 24, 2011, the National Energy Board (NEB) approved the 10-year CTS agreement reached between Enbridge and shippers on its crude oil mainline system. The CTS took effect on July 1, 2011. The CTS covers local tolls to be charged for service on the Canadian Mainline and supersedes all existing toll agreements on the Canadian Mainline during the term of the CTS. Under the terms of the CTS, the initial Canadian local toll will be based on the 2011 Incentive Tolling Settlement (ITS) recently approved by the NEB. The Canadian local toll will then be adjusted by 75% of the Canada Gross Domestic Product at Market Price Index for each of the remaining nine years of the settlement. Local tolls for service on the Lakehead System (the portion of the mainline in the United States that is owned by the Company s affiliate

Enbridge Energy Partners, L.P. (EEP)) will not be affected by the CTS and will continue to be established by EEP s existing toll agreements. The CTS also provides for an International Joint Tariff (IJT) for crude oil shipments originating in Canada on the Canadian Mainline and delivered in the United States off the Lakehead System and into Eastern Canada. The IJT is designed to provide mainline shippers with a stable and competitive long-term toll, preserving and enhancing throughput on both the Canadian Mainline and Lakehead System. With NEB approval of the CTS, shippers who initiated the Alberta Clipper hearing request with the NEB have formally withdrawn their complaints and the hearing proceedings were terminated on July 7, 2011.

Christina Lake Lateral Project

The Christina Lake Lateral Project includes a new pipeline terminal and blended products pipeline, which will allow the Cenovus and ConocoPhillips partnership to deliver increased Christina Lake production volumes directly into the Athabasca Pipeline. The expansion project will add two 375,000 barrel tanks and 26 kilometres (16 miles) of 30-inch diameter pipeline to the existing Christina Lake lateral and terminal facilities, which include two eight-inch lateral lines plus 240,000 barrels of tankage, that connect to the Athabasca Pipeline. The estimated cost of the additional facilities is approximately $0.3 billion, with expenditures to date of approximately $0.2 billion. The facilities are expected to be in service in the third quarter of 2011.

Woodland Pipeline

Enbridge entered into a joint venture agreement with Imperial Oil Resources Ventures Limited (Imperial Oil) and ExxonMobil Canada Properties (ExxonMobil) 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. The Woodland Pipeline is being undertaken as a joint venture between Enbridge, Imperial Oil and ExxonMobil. Regulatory approval for the Phase I facilities was received in June 2010 and construction is underway. The total estimated cost of the Phase I pipeline from the mine to the Cheecham Terminal and related facilities is approximately $0.5 billion, with expenditures to date of approximately $0.1 billion. Enbridge expects the pipeline will come into service in late 2012.

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. 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. With regulatory approval received in the first quarter of 2011, the expansion is expected to be completed in 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, which is 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 $0.1 billion. With regulatory approval received in the first quarter of 2011, the new pipeline is expected to be in service by late 2012.

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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 regulatory approval received in the second quarter of 2011, the facilities are expected to be in service in late 2013.

Waupisoo Pipeline Expansion

The Waupisoo Pipeline Expansion, which received regulatory approval in November 2010, will provide 65,000 barrels per day (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 project will accommodate additional shipper commitments of 229,000 bpd announced in June 2010. The estimated cost of the project is approximately $0.4 billion, with expenditures to date of approximately $0.1 billion.

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 capacity requirements of the Christina Lake Oilsands Project operated by Cenovus. This expansion will increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on type of crude oil. The estimated cost of this full expansion is approximately $0.4 billion with an expected in service date of 2013 for 430,000 bpd of total capacity, with the balance of the additional capacity 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.

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 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 on May 27, 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. On January 19, 2011, the JRP advised that prior to issuing a procedural order it required additional detail on the design and risk assessment of the pipelines. This information, together with other updates regarding the project, was provided to the JRP in March 2011. The JRP subsequently issued a Hearing Order outlining the procedures to be followed and has indicated that community hearings will be held starting in January 2012 and final hearings will commence in June 2012.

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. The Company has also signed precedent agreements with a number of shippers, of which a pro forma of the contract will be filed with the NEB before the end of the third quarter of 2011.

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.

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 Corporate 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.

Fort Hills Pipeline System

In late 2008, Fort Hills Energy L.P. (FHELP) announced that its final investment decision for the mining portion of the project was being deferred until costs could be reduced, and commodity prices and financial markets strengthened. It also announced that the Fort Hills upgrader was put on hold and that a decision to proceed with the upgrader would be made at a later date. FHELP has now completed its re-evaluation and while it is proceeding with the mining portion of the project, FHELP has decided not to proceed with the original pipeline project. Expenditures incurred to date under the original contractual arrangement of approximately $0.1 billion are collectible from FHELP. Discussions on a new pipeline project to meet the new needs of the mining project are ongoing, with no commitments currently in place.

Norman Wells Crude Oil Release

On May 9, 2011, Enbridge reported a crude oil release from a pipeline on its Norman Wells System approximately 50 kilometres south of the community of Wrigley, NWT. On May 20, 2011, Enbridge returned the Norman Wells line to service after completing the necessary repairs. Based on current estimates provided by the third party experts on site, Enbridge anticipates the release volume to be approximately 1,500 barrels. The Norman Wells pipeline is a 12-inch, 39,400 bpd line transporting sweet crude oil and stretches 869 kilometres (540 miles) from Norman Wells, NWT to Zama, AB. 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

Nexus Project

The Nexus Project is a 4.5 billion cubic feet (bcf) expansion of EGD s unregulated natural gas storage facility at Tecumseh, near Sarnia, Ontario with an expected capital cost of $42 million. The project, which has received regulatory approval, is secured by a long-term commercial contract. Construction began in the second quarter of 2011 and is expected to be completed in the fourth quarter of 2011.

Enbridge Gas New Brunswick   Transition to Cost-Based Natural Gas Distribution Rates

On November 23, 2010, Enbridge Gas New Brunswick Limited Partnership (EGNB) applied to the New Brunswick Energy and Utilities Board (NBEUB) to raise its natural gas distribution rates in the Province of New Brunswick in order to recover more of the costs of operating its natural gas delivery system in the province. Some of EGNB s large-user class customers have expressed significant opposition to the market-based rate setting mechanism that currently applies to EGNB, including public requests by some of these customers for the Province of New Brunswick to legislate a reduction in natural gas distribution rates for large-user customers. EGNB is currently engaged in negotiations with the Government of New Brunswick with respect to potential amendments to EGNB s General Franchise Agreement with the Province of New Brunswick, which may include changes to the current system under which EGNB charges market-based rates. The potential financial impact of any negotiations with the Government of New Brunswick is not yet determinable. Given the ongoing negotiations with the Government of New Brunswick and the potential that these negotiations may result in changes to EGNB s rate setting mechanism, EGNB asked the NBEUB to suspend its application to increase rates paid by its larger-user customer classes. The NBEUB approved EGNB s request on May 25, 2011.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Prairie Rose Pipeline

On July 1, 2011, Sable NGL LLC, an affiliate of Aux Sable, acquired the Stanley Condensate Recovery Plant and the Prairie Rose Pipeline for US$0.2 billion. The Stanley Plant removes condensate and will have a capacity of 80 million cubic feet per day (MMcf/d). The 12-inch diameter, 134-kilometre (83-mile) Prairie Rose Pipeline, with an estimated capacity of 110 MMcf/d connects the Stanley Plant to the Alliance Pipeline, which then delivers high energy content gas to Aux Sable s Channahan, Illinois plant for processing. Enbridge has a 42.7% equity interest in both Aux Sable and Sable NGL LLC and a 50% interest in Alliance Pipeline.

Greenwich Wind Energy Project

The Company is developing the 99-megawatt (MW) Greenwich Wind Energy Project on the northern shore of Lake Superior in Ontario with Renewable Energy Systems Canada Inc. (RES Canada). Enbridge has a 90% interest in the project and an option to acquire the remaining 10% interest. RES Canada is constructing the project under a fixed price, turnkey, engineering, procurement and construction agreement. The project utilizes 43 Siemens 2.3-MW wind turbines and, under a multi-year fixed price agreement, Siemens will provide operations and maintenance services. The Greenwich Wind Energy Project will deliver energy to the Ontario Power Authority (OPA) under a 20-year power purchase agreement. The project is expected to be completed in the fourth quarter of 2011 at an expected cost of $0.3 billion. Expenditures to date are approximately $0.2 billion.

Cedar Point Wind Energy Project

Enbridge is developing the 250-MW Cedar Point Wind Energy Project near Denver, Colorado with Renewable Energy Systems America Inc. (RES Americas), at an expected cost of approximately US$0.5 billion. RES Americas is constructing the wind project under a fixed price, turnkey, engineering, procurement and construction agreement. The project is comprised of 139 Vestas V90 1.8-MW wind turbines on 20,000 acres of leased private land. The Cedar Point Wind Energy Project will deliver electricity into the Public Service Company of Colorado grid under a 20-year, fixed price power purchase agreement. The project is expected to be completed in the fourth quarter of 2011, with expenditures to date of approximately US$0.4 billion.

Amherstburg and Tilbury Solar Projects

The Company acquired two solar energy projects totaling 20-MW generating capacity from First Solar Inc. (First Solar) for approximately $0.1 billion. The 5-MW Tilbury Solar Project, completed in December 2010, is located in Tilbury, Ontario. The

Amherstburg II Solar Project, located in Amherstburg, Ontario, consists of both a 10-MW facility and a 5-MW facility. First Solar constructed (and, in the case of the Amherstburg II Solar Project, is constructing) the projects for Enbridge under fixed price engineering, procurement and construction contracts. Construction of the Amherstburg II Solar Project is nearing completion, with commercial operation expected to commence in August 2011. Enbridge will sell the facilities power output to the OPA pursuant to 20-year power purchase agreements.

Venice Gas Processing Facility

In January 2011, the Company announced plans for an estimated US$0.2 billion expansion of the condensate processing capacity of its Venice, Louisiana facility within its offshore gas 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 will 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 in the last quarter of 2010 with Chevron USA Inc. 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 (bcf/d). WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion.

Big Foot Oil Pipeline

The Company executed definitive agreements in March 2011 with Chevron USA, Inc., 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.

Talbot Wind Energy Project

In June 2011, the Company acquired from RES Canada the remaining 10% interest in Talbot Windfarm, LP for $28 million, increasing its ownership to 100%.

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 will increase takeaway capacity from the Bakken area by an initial 145,000 bpd, which can be readily expanded to 325,000 bpd. The Bakken Expansion Program will involve United States projects undertaken by EEP at a cost of approximately US$0.4 billion and 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. In Canada, NEB hearings are scheduled for October 2011. Subject to final NEB approval in respect of the Canadian portion, the Bakken Expansion Program is expected to be completed in the first quarter of 2013.

Enbridge Energy Partners, L.P.

South Haynesville Shale Expansion

In April 2011, EEP announced that it plans to invest an additional US$0.2 billion to expand its East Texas system. 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. The projects involve construction of gathering and related treating facilities.

Two-for-One Stock Split

In April 2011, EEP announced the completion of a two-for-one split of its Common Units and i-Units. The two-for-one split was effected by a distribution of one unit for each unit outstanding and held by holders of record on April 7, 2011. Enbridge Energy Management, L.L.C. (EEM) also announced the completion of a two-for-one split of its listed shares and voting shares.

Enbridge Income Fund

Proposed Renewable Energy Assets Transfer

In May 2011, Enbridge Income Fund Holdings Inc. (ENF) and the Fund announced receipt of a proposal from Enbridge pursuant to which Enbridge would transfer three renewable energy assets to the Fund. The proposal contemplates that the Ontario Wind, Sarnia Solar and Talbot Wind energy projects would be transferred for an aggregate price of $1.3 billion, to be paid in part by the issuance of additional ordinary trust units of the Fund (Units) to both ENF and Enbridge on a pro rata basis in accordance with their present holdings in the Fund. Under the proposal, Enbridge has agreed to provide bridge debt financing to the Fund for the balance of the price. Enbridge would also grant an option to ENF to acquire some or all of the Units for which Enbridge would be entitled to subscribe. The proposed transfer is subject to all necessary approvals, including approval by the boards of ENF and the Fund and the minority shareholders of ENF, as well as regulatory approval. ENF and the Fund have formed a joint special committee comprised of independent trustees and directors to review the proposal and make recommendations to the respective boards of the Fund and ENF. If approved and completed, the transfer would further reinforce Enbridge s financial capacity to undertake attractive investment opportunities under development.

CORPORATE

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 power purchase agreement. Construction on the project has begun and Enbridge will invest up to approximately $24 million for a 20% interest in the project.

Noverco

Enbridge s investment of $144 million to acquire an additional interest in Noverco Inc. (Noverco) from Laurentides Investissements (SAS), a subsidiary of GDF SUEZ, announced in February 2011, was completed on June 30, 2011. Trencap, a partnership controlled and managed by the Caisse de Depot et Placement du Quebec, acquired Laurentides Investissements remaining 10.8% interest in Noverco; Enbridge and Trencap are now the sole shareholders of Noverco. Noverco is a holding company that owns 71% of the Gaz Metro Limited Partnership (Gaz Metro) which owns gas distribution and gas pipeline assets in the province of Quebec and gas and electric power distribution and transmission assets in the State of Vermont.

Two-for-One Stock Split

A two-for-one stock split was approved by shareholders of the Company at the May 2011 Annual and Special Meeting of Shareholders. Effective May 25, 2011, the number of outstanding shares doubled from approximately 387 million to approximately 774 million.

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

Enbridge holds an approximate 25.2% combined direct and indirect ownership interest in EEP, which is accounted for as an equity investment. Subsidiaries of Enbridge provide services to EEP in connection with its operation of the Lakehead System.

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. A significant portion of the effort to cleanup, remediate and restore the areas affected by the Line 6B crude oil release was performed by the end of 2010; however, remediation of certain identified sites continues. EEP expects to make payments for additional costs associated with remediation and restoration of the area, air and groundwater monitoring, along with other legal, professional and regulatory costs through future periods. All of the initiatives EEP undertakes in the monitoring and restoration phases are intended to restore the incident area to the satisfaction of the appropriate regulatory authorities.

EEP revised its cost estimate for this crude oil release to US$585 million ($101 million after-tax net to Enbridge) at June 30, 2011, an increase of US$35 million ($6 million after-tax net to Enbridge) from March 31, 2011. This estimate is before insurance recoveries and excluding fines and penalties. The expected losses associated with the Line 6B crude oil release include those costs that are considered probable and that could be reasonably estimated at June 30, 2011. The estimates do not include amounts capitalized or any fines, penalties and claims associated with the release that may later become evident. 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. EEP has the potential of incurring 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 is continuing to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System for any additional requirements. The clean up, remediation and restoration of the areas affected by the release has been substantially completed. In connection with this crude oil release, EEP revised its cost estimate to US$48 million ($8 million after-tax net to Enbridge), an increase of US$3 million from March 31, 2011, before insurance recoveries and excluding fines and penalties. EEP has the potential to incur additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation.

Insurance Recoveries

The Company maintains 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 releases from Line 6A and 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. Assuming all of the claims for the releases are recoverable under this insurance policy, the occurrence-based coverage remaining under the commercial liability insurance policies related to costs associated with Lines 6A and 6B, and other claims of Enbridge and its subsidiaries and affiliates, including EEP, is approximately US$20 million based on estimates as at June 30, 2011. It is anticipated that substantially all of the costs incurred from the crude oil releases will ultimately be recoverable under the Company s existing insurance policies, except for fines and penalties and other amounts for which the Company is not insured. EEP recognized US$15 million ($3 million after-tax net to Enbridge) and US$50 million ($8 million after-tax net to Enbridge) of insurance recoveries in the three and six months ended June 30, 2011, respectively, for claims filed in connection with the Line 6B crude oil release. Of the US$50 million of insurance recoveries recognized in earnings, EEP received insurance payments of US$35 million in the second quarter of 2011 while the remaining US$15 million is included in EEP s receivables. EEP expects to record a receivable for additional amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery is probable.

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

Pipeline Integrity Commitment

In connection with the restart of Line 6B, EEP committed to accelerate a process, initiated prior to the crude oil release, to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement with the United States Department of Transportation s Pipeline and Hazardous Materials Safety Administration (PHMSA), EEP completed remediation of those pipeline anomalies it identified between 2007 and 2009 that were scheduled for refurbishment, and anomalies identified for action in a July 2010 PHMSA notification, on schedule within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, EEP also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied into Line 6B during June 2011.

In May 2011 EEP announced plans to replace 120 kilometres (75 miles) of non-contiguous sections of Line 6B of its Lakehead System at an estimated cost of US$286 million. 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 expected 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. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with EEP s capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature. EEP recently 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.

In February 2011, EEP filed a tariff supplement with the Federal Energy Regulatory Commission (FERC), to be effective on April 1, 2011, for recovery of US$175 million of capital costs and US$5 million of operating costs which are related to the 2010 and 2011 Line 6B Integrity Program. The costs associated with the Line 6B Integrity Program, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30 year period, while operating costs will be recovered through EEP s annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work. The US$30 million of additional costs do not currently have recovery under the tariff surcharge.

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. Currently, approximately 25 actions or claims have been filed against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against Enbridge, EEP or their affiliates as at June 30, 2011. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in a United States state court. The parties are operating under an agreed interim order which is expected to mature into a final order in the near future, thereby resolving the proceeding.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Canadian Mainline	**81**	78	**163**	162
Regional Oil Sands System	**26**	20	**53**	38
Southern Lights Pipeline	**17**	21	**36**	45
Spearhead Pipeline	**-**	10	**10**	15
Feeder Pipelines and Other	**-**	4	**(2)**	7
Adjusted Earnings	**124**	133	**260**	267
Canadian Mainline - shipper dispute settlement	**14**	-	**14**	-
Canadian Mainline - Line 9 tolling adjustment	**13**	-	**13**	-
Canadian Mainline - unrealized derivative fair value gains	**46**	-	**46**	-
Earnings	**197**	133	**333**	267

Adjusted earnings for the three months ended June 30, 2011 were $124 million compared with $133 million for the three months ended June 30, 2010. Adjusted earnings for the six months ended June 30, 2011 were $260 million, a decrease of $7 million compared with adjusted earnings of $267 million in the prior year comparable period. The Company continued to realize earnings growth on the Canadian Mainline and the Regional Oil Sands System; however, such growth was offset by lower contributions from its Southern Lights and Spearhead pipelines.

Earnings for the second quarter of 2011 reflected higher negotiated ITS tolls applicable to the discrete three month period and favourable operating cost performance. These positive effects were partially offset by higher depreciation, interest costs and taxes incurred during the three months ended June 30, 2011 compared with the corresponding period of 2010. These same factors impacted Canadian Mainline earnings for the six months ended June 30, 2011. Also included in Canadian Mainline earnings for the six months ended June 30, 2011 were in-service earnings from Alberta Clipper compared with allowance for equity funds used during construction (AEDC) recognized while the project was under construction until its in-service date of April 1, 2010.

Canadian Mainline earnings will be governed by the CTS effective July 1, 2011. Prior to 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 guidance. The Company will discontinue the application of rate-regulated accounting to its Canadian Mainline on a prospective basis commencing July 1, 2011. While the CTS is based on previous tolling settlements and cost-of-service principles, the Company retains some risk associated with volume throughput and capital and operating costs, subject to various protection mechanisms. As a result, the Canadian Mainline operations no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment. Canadian Mainline property, plant and equipment balances at June 30, 2011 will continue to be recognized at historic cost subject to normal course impairment assessment. As well, the regulatory asset related to future income taxes, which totaled $470 million at June 30, 2011, will continue to be recognized as the Company retains the ability to recover future income taxes under an NEB order governing flow-through income tax treatment.

Regional Oil Sands System earnings increased as a result of higher shipped volumes and increased tolls on certain laterals, as well as an increased contribution from Hardisty Caverns Limited Partnership which is now wholly-owned by the Company. Another factor contributing to the increase was lower depreciation expense due to extended estimated useful lives of certain assets reflecting increased probable reservoir supply and commercial viability.

The decrease in Southern Lights Pipeline earnings reflected a decrease in leasing income from a pipeline which was transferred to the Canadian Mainline effective May 1, 2010. Both the Canadian and United States portions of the tariff for uncommitted shippers on the Southern Lights Pipeline have been challenged. Accordingly, a FERC hearing process was initiated and a hearing has been scheduled for January 10, 2012. The Canadian Southern Lights toll hearing has been set by the NEB for November 15, 2011. No material financial impacts to the Company are anticipated from either of these proceedings.

The decrease in Spearhead Pipeline earnings reflected lower throughput volumes as a result of current market pricing dynamics at Cushing, Oklahoma, as well as lower earnings from the recognition of expired shipper make-up rights in both the three and six months ended June 30, 2011 compared with the same periods of 2010.

The earnings decrease in Feeder Pipelines and Other was primarily due to a decreased contribution from Toledo Pipeline, which was impacted by integrity work on Line 6B of EEP s Lakehead System, as well as an increase in business development costs.

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

- Earnings in 2011 for Canadian Mainline included $14 million from the settlement of a shipper dispute related to oil measurement adjustments in prior years.
- 2011 Canadian Mainline earnings included a Line 9 tolling adjustment related to services provided in prior periods.
- Canadian Mainline earnings for 2011 reflected unrealized fair value gains on derivative financial instruments used to risk manage exposures inherent within the CTS agreement, namely foreign exchange and power cost variability.

GAS DISTRIBUTION

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Enbridge Gas Distribution (EGD)	**30**	22	**109**	98
Other Gas Distribution and Storage	**9**	8	**22**	20
Adjusted Earnings	**39**	30	**131**	118
EGD - colder/(warmer) than normal weather	**2**	(10)	**13**	(18)
Earnings	**41**	20	**144**	100

Adjusted earnings from Gas Distribution were $39 million and $131 million for the three and six months ended June 30, 2011, respectively, compared with $30 million and $118 million for the three and six months ended June 30, 2010.

EGD adjusted earnings were $30 million and $109 million for the three and six months ended June 30, 2011, respectively, compared with adjusted earnings of $22 million and $98 million for the three and six months ended June 30, 2010. The increase in EGD s adjusted earnings for both the second quarter and the first six months of 2011 was primarily due to favourable operating performance including the timing of certain expenditures. Positive earnings contributions included customer growth, lower interest expense and the favourable impacts from lower statutory income tax rates, partially offset by higher depreciation expense and lower variable charges to customers. The progressive substitution of lower per unit volumetric charges to customers with corresponding increases in fixed charges modifies EGD s quarterly earnings profile relative to the prior year, but does not materially impact full year earnings as earnings are shifted from the colder winter months to the warmer summer months.

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 June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Enbridge Offshore Pipelines (Offshore)	**(3)**	5	**(1)**	14
Alliance Pipeline US	**6**	7	**13**	13
Vector Pipeline	**4**	4	**9**	8
Aux Sable	**13**	9	**24**	16
Energy Services	**17**	(1)	**26**	9
Other	**7**	(2)	**12**	1
Adjusted Earnings	**44**	22	**83**	61
Offshore - property insurance recoveries from hurricanes	**-**	-	**-**	2
Aux Sable - unrealized derivative fair value gains/(losses)	**(1)**	18	**(7)**	14
Energy Services - unrealized derivative fair value gains/(losses)	**(9)**	5	**9**	(8)
Energy Services - Lehman credit recovery	**-**	1	**-**	1
Earnings	**34**	46	**85**	70

Adjusted earnings from Gas Pipelines, Processing and Energy Services were $44 million and $83 million for the three and six months ended June 30, 2011, respectively, compared with $22 million and $61 million for the three and six months ended June 30, 2010. The increase was primarily due to higher adjusted earnings in Aux Sable, Energy Services and Other, partially offset by losses in Offshore.

The decrease in Offshore adjusted earnings was primarily due to volume declines including natural production declines in existing reserves. The slower regulatory permitting process has impacted the level and timing of drilling activity in the Gulf of Mexico and the resultant production volumes available to ship on the Company s Offshore system. Higher operating and administrative costs and depreciation expense also contributed to the decrease in earnings in both the three and six-month periods ended June 30, 2011 compared with the corresponding periods of 2010. Offshore adjusted earnings for the six months ended June 30, 2010 included $2 million in insurance proceeds related to reimbursement for business interruption lost revenues and operating expenses associated with a hurricane in 2008.

Aux Sable adjusted earnings increased primarily due to stronger realized fractionation margins which resulted in higher contributions from the upside sharing mechanism in its production sales agreement.

The increase in Energy Services adjusted earnings was largely attributable to improved margin opportunities in crude oil marketing.

The increase in Other adjusted earnings included strong contributions from the Sarnia Solar expansion and Talbot Wind Energy Project, both of which were completed in the latter part of 2010.

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

- Offshore earnings for the six months ended June 30, 2010 included insurance proceeds related to the replacement of damaged infrastructure as a result of a 2008 hurricane.

- 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 inventory and the revaluation of financial derivatives used to risk manage the profitability of forward transportation and storage transactions.

- Energy Services earnings for 2010 included a partial recovery of $1 million from the sale of its receivable from Lehman Brothers.

SPONSORED INVESTMENTS

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Enbridge Energy Partners (EEP)	**33**	31	**65**	61
Enbridge Energy, L.P. - Alberta Clipper US (EELP)	**10**	8	**22**	18
Enbridge Income Fund (the Fund)	**12**	12	**25**	23
Adjusted Earnings	**55**	51	**112**	102
EEP - leak insurance recoveries	**3**	-	**8**	-
EEP - leak remediation costs	**(6)**	-	**(6)**	-
EEP - shipper dispute settlement	**8**	-	**8**	-
EEP - lawsuit settlement	**-**	-	**1**	-
EEP - impact of unusual weather conditions	**-**	-	**(1)**	-
EEP - unrealized derivative fair value gains	**3**	4	**-**	5
EEP - Lakehead System billing correction	**-**	1	**-**	1
EEP - dilution gain on Class A unit issuance	**-**	1	**-**	1
Earnings	**63**	57	**122**	109

Sponsored Investments adjusted earnings were $55 million for the three months ended June 30, 2011 compared with $51 million for the three months ended June 30, 2010. For the six months ended June 30, 2011, adjusted earnings were $112 million compared with $102 million in the comparable prior period.

EEP adjusted earnings were $65 million for the six months ended June 30, 2011 compared with $61 million for the six months ended June 30, 2010. The increase was largely attributable to the natural gas business and higher incentive income. Increased earnings in the natural gas business were due to increased natural gas and NGL volumes, including those associated with the acquisition of the Elk City System in September 2010, partially offset by an increase in operating and administrative costs, depreciation expense and higher financing costs incurred as a result of additional assets placed in service during 2010. Earnings for the first half of 2011 also included a full period of contributions from Alberta Clipper following its completion and start up in April 2010.

The increase in EELP earnings was due to the completion and start up of Alberta Clipper in April 2010.

Earnings for the Fund totaled $25 million for the first half of 2011 and reflected increased contributions from the Saskatchewan System following completion of is Phase II expansion project in December 2010, partially offset by additional financing costs.

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

- EEP 2011 earnings included insurance recoveries associated with the Line 6B crude oil release. *See Recent Developments - EEP Lakehead System Line 6B and 6A Crude Oil Releases.*

- 2011 earnings from EEP included a charge of $6 million (net to Enbridge) related to revised estimated costs, before insurance recoveries, associated with the Line 6B and 6A crude oil releases. *See Recent Developments - EEP Lakehead System Line 6B and 6A Crude Oil Releases.*

- EEP 2011 earnings included proceeds of $8 million (net to Enbridge) from the settlement of a shipper dispute related to oil measurement adjustments in prior years.

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

- EEP 2011 earnings included an unfavourable effect of $1 million (net to Enbridge) related to decreased volumes due to uncharacteristically cold weather in February 2011.

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

- EEP 2010 earnings included Lakehead System billing corrections.

- EEP 2010 earnings included dilution gains (after tax and noncontrolling interest).

CORPORATE

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	**2011**	2010
(millions of Canadian dollars)				
Noverco	**3**	(3)	**17**	17
Other Corporate	**(5)**	(1)	**(9)**	(15)
Adjusted Earnings/(Loss)	**(2)**	(4)	**8**	2
Corporate - unrealized derivative fair value losses	**(65)**	(88)	**(49)**	(62)
Corporate - unrealized foreign exchange gains/(losses) on translation of intercompany balances, net	**(1)**	(26)	**17**	(6)
Corporate - impact of tax rate changes	**(8)**	-	**(8)**	-
Loss	**(76)**	(118)	**(32)**	(66)

Total Corporate adjusted loss was $2 million for the three months ended June 30, 2011 compared with $4 million for the three months ended June 30, 2010. Total Corporate adjusted earnings were $8 million for the six months ended June 30, 2011 compared with $2 million for the six months ended June 30, 2010.

Noverco earnings reflected contributions from the Company s preferred share investment and Noverco s underlying gas distribution investments. Earnings from Noverco are seasonal in nature and will therefore vary from period-to-period. The increase in earnings for the second quarter was a result of stronger Gaz Metro earnings in 2011 compared with 2010.

Other Corporate adjusted loss for the second quarter increased primarily as a result of higher operating and administrative costs and a lower income tax recovery, partially offset by lower financing costs.

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

- Earnings for each period included the change in the unrealized fair value losses of derivative financial instruments related to forward foreign exchange risk management positions.

- Earnings included net unrealized foreign exchange gains or losses on the translation of foreign-denominated intercompany balances.

- Earnings for 2011 were impacted by unfavourable tax rate changes.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations and the issuance of replacement debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common share dividends. At June 30, 2011, excluding the Southern Lights project financing, the Company had $5,669 million of committed credit facilities of which $3,395 million was drawn or allocated to backstop commercial paper. Inclusive of unrestricted cash and cash equivalents of $229 million, the Company had net available liquidity at June 30, 2011 of $2,503 million. The net available liquidity 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 optimize pricing and other terms. The following table provides details of the Company s credit facilities at June 30, 2011.

	Maturity Dates[2]	Total Facilities	Credit Facility Draws[3]	Available
(millions of Canadian dollars)				
Liquids Pipelines[4]	2012	200	121	79
Gas Distribution[5]	2011-2012	717	246	471
Sponsored Investments[6]	2013	300	169	131
Corporate[7]	2012-2014	4,452	2,859	1,593
		5,669	3,395	2,274
Southern Lights project financing[1]	2012-2014	1,619	1,430	189
Total Credit Facilities		7,288	4,825	2,463

1 Total facilities inclusive of $58 million for debt service reserve letters of credit.

2 Total facilities includes $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.

4 In July 2011, this credit facility was amended to increase total available credit to $300 million and to extend the maturity date to 2013.

5 In July 2011, the maturity date on the $700 million EGD credit facility was extended to 2013.

6 In July 2011, the Fund amended its credit facility to include an accordion feature under which up to $200 million of additional standby credit may be provided.

7 In August 2011, the Company extended the maturity date on its $2,250 million term credit facilities to 2016. Also in August 2011, the Company secured additional revolving facilities of $500 million with a maturity date of 2013.

OPERATING ACTIVITIES

Cash provided from operating activities was $575 million and $1,532 million for the three and six months ended June 30, 2011, respectively, compared with $511 million and $1,157 million for the three and six months ended June 30, 2010. Cash from operating activities was positively impacted in 2011 by favourable operating performance, primarily in Energy Services, as well as the impact of colder weather within the EGD franchise area. Also contributing to the change in cash from operating activities was an increase in cash distributions from the Company s investments in Noverco and in EELP, which owns the United States segment of Alberta Clipper. Also contributing to the increase were the net collection of regulatory assets and liabilities, lower cash taxes and variations in working capital requirements, primarily natural gas inventory at EGD, the value of which is dependent on commodity prices and seasonal volumetric drawdown rates.

There are no material restrictions on the Company s cash with the exception of proportionately consolidated joint venture cash of $62 million, which cannot be accessed until distributed to the Company, restricted cash of $4 million related to Southern Lights project financing and cash in trust of $8 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities for the three and six months ended June 30, 2011 was $622 million and $1,087 million, respectively, compared with $558 million and $1,187 million for the three and six months ended June 30, 2010. Cash used in investing activities included $406 million (2010 - $490 million) and $813 million (2010 - $865 million) of additions to property, plant and equipment for the three and six months ended June 30, 2011, respectively, largely directed towards the Company s growth projects. In June 2011, the Company acquired an additional interest in Noverco for $144 million and also acquired the remaining 10% interest in the Talbot Wind Energy Project for $28 million. Investing activities for the six months ended June 30, 2010 included a use of cash related to long-term investments and affiliate lending, primarily the Company s investing in and funding of EELP while the Alberta Clipper Project was under construction.

FINANCING ACTIVITIES

Cash used in financing activities totaled $378 million for the six months ended June 30, 2011 compared with a source of cash of $107 million in the corresponding period of 2010. Year-to-date financing activities at June 30, 2011 included a term note repayment of $150 million as well as a draw of $91 million from short-term borrowings, commercial paper and credit facility draws to meet routine operating and capital requirements. In comparison, term note issuances of $500 million and $750 million were completed in March and April 2010, respectively, which in part funded repayment of short-term sources totaling $449 million and a term note repayment of $504 million in the six months ended June 30, 2010. The Company also repaid $40 million of its Southern Lights project financing facility in the first six months of 2011, compared with a net draw of $51 million in the corresponding period of 2010.

Participants in the Company s Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended June 30, 2011, dividends declared were $190 million (2010 - $161 million), of which $136 million (2010 - $104 million) were paid in cash and reflected in financing activities. The remaining $54 million (2010 - $57 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the six months ended June 30, 2011, dividends declared were $378 million (2010 - $322 million), of which $260 million (2010 - $209 million) were paid in cash and reflected in financing activities. The remaining $118 million (2010 - $113 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three and six months ended June 30, 2011, 28% (2010 - 35%) and 31% (2010 - 35%) of total dividends declared were reinvested.

On August 4, 2011, the Enbridge Board of Directors declared quarterly dividends of $0.245 per common share on a post-split basis, representing a 15% year-over-year increase, and $0.34375 per Series A Preferred Share. Both dividends are payable on September 1, 2011 to shareholders of record on August 15, 2011.

Capital Expenditure Commitments

The Company has signed contracts for the purchase of services, pipe and other materials totaling $2,068 million.

QUARTERLY FINANCIAL INFORMATION[1]

	2011		2010				2009	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
(millions of Canadian dollars, except per share amounts)								
Revenues	**4,981**	4,713	4,143	3,502	3,505	3,977	3,187	2,629
Earnings attributable to common shareholders	**259**	393	326	157	138	342	300	304
Earnings per common share[2]	**0.35**	0.52	0.44	0.21	0.19	0.47	0.40	0.42
Diluted earnings per common share[2]	**0.34**	0.52	0.43	0.21	0.18	0.46	0.40	0.41
Dividends per common share[2]	**0.2450**	0.2450	0.2125	0.2125	0.2125	0.2125	0.1850	0.1850
EGD - warmer/(colder) than normal weather	**(2)**	(11)	(6)	-	10	8	(3)	-
Net unrealized derivative fair value and intercompany foreign	**27**	(43)	(71)	(45)	87	(30)	(27)	(166)

exchange (gains)/losses

1 Quarterly financial information has been extracted from financial statements prepared in accordance with Canadian GAAP.

2 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 resultant 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 undertook a substantial capital program in recent years 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 *Recent Developments*.

In addition to the impacts of EGD weather and unrealized gains and losses outlined above, significant items that impacted the quarterly earnings were as set forth below.

- Second quarter 2011 earnings reflected increased earnings from EGD due to favourable operating performance, as well as proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior years within Liquids Pipelines and Sponsored Investments.

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

- Fourth quarter 2010 earnings reflected a dilution gain on reduced ownership in EEP, partially offset by additional leak remediation costs and the elimination of annual performance metrics under the Liquids Pipelines 2010 interim toll agreement.

- Reflected in earnings for the third and fourth quarters of 2010 are leak remediation costs and lost revenue associated with the Line 6B and Line 6A crude oil releases in the amounts of $85 million and $21 million, respectively.

- 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. Previous quarters include AEDC while the projects were under construction.

RISK MANAGEMENT

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 movements. In June 2011, the Company entered into additional derivative instruments to mitigate the volatility of short term interest rates on interest expense through 2015 at an average rate of 2.42%.

At June 30, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in a $4 million increase (2010 - $1 million) in earnings and would have caused a $203 million increase (2010 - $164 million) in Other Comprehensive Income (OCI) due to the revaluation of interest rate derivatives outstanding at June 30, 2011, and a $12 million decrease (2010 - $11 million) in earnings due to increased interest expense related to the Company s variable rate debt outstanding at June 30, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Earnings for both the three and six months ended June 30, 2011 included a loss of $9 million (2010 - $nil) as a result of hedge ineffectiveness on its interest rate derivatives.

Foreign Exchange and Commodity Price Risk

As a result of renegotiations with shippers on certain pipelines, the Company is now exposed to additional foreign exchange rate risk on United States dollar denominated revenues, and additional commodity price risk resulting from increased exposure to variable crude oil and power prices.

The Company s earnings, cash flows and OCI are subject to foreign exchange variability, primarily arising from its United States dollar denominated investments, subsidiaries and certain revenues denominated in United States dollars. In June 2011, the Company entered into additional derivative instruments to mitigate cash flow volatility due to the effect of future foreign exchange rate fluctuations, including the collection of tolls on the Canadian Mainline in United States dollars as a result of the CTS agreement. Specifically, for the years ending December 31, 2011 through 2015, the Company has entered into instruments to mitigate between 80% and 90% of this exposure at United States to Canadian dollar foreign exchange rates of $0.96, $0.97, $1.00, $1.02 and $1.0256, respectively.

The impact of a $0.05 strengthening of the Canadian dollar across the forward curve relative to the United States dollar at June 30, 2011 would have resulted in a $198 million increase to earnings (2010 - $85 million). A sensitivity analysis excludes financial instruments that are not monetary items and the impact of translating the Company s United States dollar denominated self-sustaining subsidiaries on OCI; therefore, a sensitivity analysis on the impacts to OCI is considered unrepresentative of the inherent risk to OCI.

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. During the three months ended June 30, 2011, the Company entered into additional power swap and crude oil derivative instruments to fix a portion of the variable price exposures arising from certain commodity agreements.

The Company has defined Earnings at Risk (EaR) limits for different components of businesses exposed to commodity price risk. Positions giving rise to commodity price exposure are monitored against these EaR limits daily. For the six months ended June 30, 2011 and 2010, the Company has estimated the following maximum adverse change in projected 12 month earnings that has a maximum 2.5% chance of resulting from total commodity price risk over a one month period:

(millions of Canadian dollars)	**2011**	2010
Average EaR during the year	**23**	19
High EaR during the year	**27**	21
Low EaR during the year	**18**	16
Closing EaR at year end	**25**	20

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

	June 30, 2011		December 31, 2010	
	Maturity	Notional Principal or Quantity Outstanding	Maturity	Notional Principal or Quantity Outstanding
U.S. dollar forwards - purchase *(millions of United States dollars)*	**2011-2020**	**1,303**	2011-2020	1,185
U.S. dollar forwards - sell *(millions of United States dollars)*	**2011-2020**	**7,496**	2011-2020	3,516
Interest rate contracts *(millions of Canadian dollars)*	**2011-2029**	**13,368**	2011-2029	10,772
Commodity contracts - Energy *(bcfe)*				