Primerica, Inc.
Form 4
March 04, 2014

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

OMB APPROVAL

OMB Number:	3235-0287
Expires:	January 31, 2005
Estimated average burden hours per response...	0.5

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Britt Chess E.

(Last) (First) (Middle)

1 PRIMERICA PARKWAY

(Street)

DULUTH, GA 30099

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
Primerica, Inc. [PRI]

3. Date of Earliest Transaction (Month/Day/Year)
03/01/2014

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Executive Vice President

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	03/01/2014		F		838 (1)	D	$ 44.82	71,111	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Britt Chess E. 1 PRIMERICA PARKWAY DULUTH, GA 30099			Executive Vice President	

Signatures

/s/ Stacey K. Geer, attorney in fact	03/04/2014
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Represents shares withheld to cover taxes due upon the vesting of restricted shares.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. width="10%" valign="bottom" style="padding:0in 0in 0in 0in;width:10.0%;">

180

Corporate

48

(77

)

9

(108

)

Earnings/(loss) attributable to common shareholders

189

(5

)

464

661

Earnings/(loss) per common share

0.24

(0.01

)

0.60

0.88

Diluted earnings/(loss) per common share

0.24

(0.01

)

0.59

0.87

Earnings attributable to common shareholders were $189 million for the three months ended September 30, 2012, or $0.24 per common share, compared with a loss of $5 million, or $0.01 per common share, for the three months ended September 30, 2011. This increase primarily reflected a significant reduction in the net unrealized fair value losses on financial derivatives recognized in the third quarter of 2012 compared with 2011. The most significant reductions were on derivatives related to foreign exchange risk management positions, partially offset by increased unrealized losses associated with the revaluation of financial derivatives used to risk manage the profitability of transportation and storage transactions. Increased earnings from Liquids Pipelines as a result of strong volumes and favourable operating performance under the Competitive Toll Settlement (CTS), as well as operating earnings from Seaway Pipeline, also contributed to the overall earnings increase. For the three months ended September 30, 2012, $19 million of insurance recoveries net of additional leak remediation costs associated with the Line 6B crude oil release was reflected in earnings from Enbridge Energy Partners, L.P. (EEP), compared with net leak remediation costs of $8 million for the third quarter of 2011.

Earnings attributable to common shareholders were $464 million for the nine months ended September 30, 2012, or $0.60 per common share, compared with $661 million, or $0.88 per common share, for the nine months ended September 30, 2011. The decrease in year-to-date earnings reflected the same drivers as the third quarter, although net unrealized fair value losses on financial derivatives increased significantly in 2012 compared with 2011. The most significant change, recognized in Energy Services, related to the revaluation of financial derivatives used to risk manage the profitability of transportation and storage transactions.

1

FORWARD-LOOKING INFORMATION

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

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

Enbridge s forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, 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 (earnings/(loss)) adjusted for unique or unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments. Management believes that the presentation of adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, assess performance of the Company and set the Company s dividend payout target. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. See *Non-GAAP Reconciliations* for a reconciliation of the GAAP and non-GAAP measures.

Explanation of Responses:

ADJUSTED EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**191**	150	**501**	410
Gas Distribution	**(18)**	(4)	**113**	125
Gas Pipelines, Processing and Energy Services	**36**	41	**117**	122
Sponsored Investments	**69**	61	**196**	170
Corporate	**(9)**	(9)	**(5)**	-
Adjusted earnings	**269**	239	**922**	827
Adjusted earnings per common share	**0.34**	0.32	**1.20**	1.10

Adjusted earnings were $269 million, or $0.34 per common share, for the three months ended September 30, 2012 compared with $239 million, or $0.32 per common share, for the three months ended September 30, 2011. Adjusted earnings were $922 million, or $1.20 per common share, for the nine months ended September 30, 2012 compared with $827 million, or $1.10 per common share, for the nine months ended September 30, 2011. The following factors impacted the increase in adjusted earnings for both the three and nine months ended September 30, 2012 compared with 2011.

- Within Liquids Pipelines, strong volumes on Canadian Mainline and Spearhead Pipeline contributed to an overall increase in adjusted earnings. Incremental oil sands crude production in Alberta and strong production growth out of the Bakken in North Dakota have bolstered supply to midwest markets and placed increased downward pressure on crude oil prices in this market. Enbridge believes this pressure will at least be partially reduced upon completion of its market access projects. This discounted crude oil, coupled with strong refining margins, is increasing demand in the midwest for Canadian and Bakken crude oil supply and driving increased long haul barrels on Canadian Mainline and the Lakehead System owned by EEP. Enbridge s 50% interest in the Seaway Pipeline, acquired in late 2011, also favourably impacted earnings for the three and nine months ended September 30, 2012.

- Within Gas Distribution, Enbridge Gas Distribution s (EGD) adjusted earnings were impacted by increased system integrity and operating and administrative costs, partially offset by customer growth and lower interest expense. Enbridge Gas New Brunswick (EGNB) continued to see decreased earnings as a result of changes in ratemaking regulations by the New Brunswick Government in April 2012. EGNB is now subject to variability in volumes delivered; therefore, earnings will fluctuate with seasonal demand.

- Within Sponsored Investments, increased EEP adjusted earnings primarily reflected higher average daily delivery volumes on all major liquids systems, partially offset by significantly lower natural gas and NGL prices affecting its natural gas business and additional operating and administrative costs.

- Also within Sponsored Investments, increased contributions from Enbridge Income Fund (the Fund) due to the acquisition and strong operating performance of its renewable energy assets were partially offset by associated financing costs and taxes.

- The increase in Corporate adjusted loss period-over-period was due to higher preference share dividends and higher taxes, partially offset by lower residual corporate interest costs.

RECENT DEVELOPMENTS

CHIEF EXECUTIVE OFFICER SUCCESSION

On September 5, 2012, the Board of Directors (Board) announced the appointment of Al Monaco to the position of Chief Executive Officer (CEO), effective October 1, 2012. Mr. Monaco continues to serve as President and as a member of the Board. Also effective October 1, 2012, Patrick D. Daniel retired as CEO and from Enbridge s Board. Prior to being appointed President in February 2012, Mr. Monaco held the role of President, Gas Pipelines, Green Energy and International. With Mr. Monaco s appointment as President of Enbridge, Leon Zupan was appointed President, Gas Pipelines and Richard Bird, Executive Vice President, Chief Financial Officer and Corporate Development, assumed responsibility for Enbridge s Green Energy, International and Energy Services businesses.

LIQUIDS PIPELINES

Southern Lights Pipeline

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

Elk Point Pump Station Facility Oil Release

On June 19, 2012, Enbridge reported an oil release at its Elk Point pumping station on Line 19 (Athabasca Pipeline), approximately 70 kilometres (44 miles) south of Bonnyville, Alberta and approximately 24 kilometres (15 miles) from the town of Elk Point, Alberta. On June 24, 2012, the Company restarted the Elk Point pumping station after completing necessary repairs. The contaminated soil and free product has been removed from the site for processing and disposal. Further environmental testing and monitoring of the site is being conducted. Estimated volume of the release is approximately 1,400 barrels which were largely contained within the station. Management does not believe this incident will have a material impact on the Company s consolidated financial position or results of operations.

Norman Wells Pipeline Crude Oil Release

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

GAS DISTRIBUTION

Enbridge Gas New Brunswick Regulatory Matters

On December 9, 2011 the Government of New Brunswick tabled and then subsequently passed legislation related to the regulatory process for setting rates for gas distribution within the province. The legislation permitted the government to implement new regulations which could affect the franchise agreement between EGNB and the province, impact prior decisions by the province s independent regulator and influence the regulator s future decisions. However, significant details of the rate setting

4

process were left to be established in the new regulations and, as such, the effect of such legislation was not determinable at that time.

A final rates and tariffs regulation was subsequently enacted by the Government of New Brunswick on April 16, 2012. Based on the amended rate setting methodology and specific conditions outlined therein, EGNB no longer met the criteria for the continuation of rate regulated accounting. As a result, the Company eliminated from its Consolidated Statements of Financial Position a deferred regulatory asset of $180 million and a regulatory asset with respect to capitalized operating costs of $103 million, net of an Income tax recovery of $21 million.

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

On April 26, 2012, the Company, Enbridge Energy Distribution Inc. (EEDI) and EGNB commenced an action against the Province of New Brunswick in the New Brunswick Court of Queen s Bench, claiming damages in the amount of $650 million as a result of the continuing breaches by the province of the General Franchise Agreement it signed with Enbridge in 1999. Additionally, on May 2, 2012, the Company, EEDI and EGNB filed a Notice of Application with the New Brunswick Court of Queen s Bench seeking a declaration from the Court that the rates and tariffs regulation is invalid. In a decision released on August 23, 2012, the Court dismissed EGNB s Application. EGNB has filed a Notice of Appeal with the New Brunswick Court of Appeal but a hearing date for the appeal has not yet been scheduled. On September 20, 2012, the New Brunswick Energy and Utilities Board (EUB) issued a decision regarding EGNB s rates that were to take effect as of October 1, 2012. The EUB s decision applies the rate-setting methodology set out in the rates and tariffs regulation. EGNB has filed an application for judicial review of the EUB s rate order with the New Brunswick Court of Appeal. There is no assurance these actions will be successful or will result in any recovery.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Greenwich Wind Energy Project

In May 2012, the Company acquired from Renewable Energy Systems Canada Inc. the remaining 10% interest in the Greenwich Wind Energy Project (Greenwich) through Greenwich Windfarm, LP, for $27 million, increasing its ownership to 100%. See *Recent Developments Sponsored Investments Enbridge Income Fund Proposed Crude Oil Storage and Renewable Energy Assets Transfer*.

SPONSORED INVESTMENTS

ENBRIDGE ENERGY PARTNERS, L.P.

Class A Common Units Issuance

In September 2012, EEP issued 16.1 million Class A Common Units for net proceeds of approximately US$447 million. As a result of the Common Units issuance, Enbridge recognized a $27 million dilution gain in Equity and reduced its effective ownership interest in EEP from 23% to 22%.

Lakehead System Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP s Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,200 barrels. EEP received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012, followed by an amended CAO on August 1, 2012. The CAOs required EEP to take certain corrective actions, some of which have already been completed and some are still ongoing, as part of an overall plan for its Lakehead System. A notable part of the CAOs was to hire an independent third party pipeline expert to review and assess EEP s overall integrity program. An independent third party expert was contracted during the third quarter of 2012 and their work is currently ongoing.

Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. The pressure restrictions will remain in place until such time EEP can demonstrate that the root cause of the incident has been remediated.

EEP has updated the disclosed estimate for repair and remediation related costs associated with this crude oil release to approximately US$12 million ($2 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenue, and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge s comprehensive insurance policy, although it does not expect any recoveries to be significant.

Lakehead System Line 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

During the second quarter of 2012, local authorities allowed the Kalamazoo River and Morrow Lake, which were affected by the Line 6B crude oil release, to be re-opened for recreational use. EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with submerged oil and sheen monitoring and recovery operations, including remediation and restoration of the area, containment management, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, EEP received a Notice of Probable Violation (NOPV) from the PHMSA related to the July 26, 2010 Line 6B crude oil release, which resulted in payment of a US$3.7 million civil penalty in the third quarter of 2012. EEP included the amount of the penalty in its total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012 the National Transportation Safety

Board presented the results of its investigation into the Line 6B crude oil release and subsequently publicly posted its final report on July 26, 2012.

As at September 30, 2012, EEP had revised the total incident cost accrual to US$810 million ($136 million after-tax attributable to Enbridge), primarily due to an estimate of extended oversight by regulators and additional legal costs associated with various lawsuits, which is an increase of US$25 million ($5 million after-tax attributable to Enbridge) from its estimate at June 30, 2012. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the PHMSA civil penalty described above. On October 3, 2012, EEP received a letter from the Environmental Protection Agency (EPA) regarding a Proposed Order for potential incremental containment and active recovery of submerged oil. EEP is in discussions with the EPA regarding the agency s intent with respect to certain elements of the Proposed Order and the appropriate scope of these activities. As such, EEP has not included significant additional costs related to this Proposed Order in its total incident cost accrual and it is impracticable to provide an estimate at this time.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2012. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System near Romeoville, Illinois in September 2010 for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at approximately US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties. EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP s remediation spending through September 30, 2012, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$170 million ($24 million after-tax attributable to Enbridge) of insurance recoveries as reductions to Environmental costs, net of recoveries, for the Line 6B crude oil release in the Consolidated Statements of Earnings for the three and nine months ended September 30, 2012, compared with US$85 million ($13 million after-tax attributable to Enbridge) and US$135 million ($21 million after-tax attributable to Enbridge) for the three and nine months ended September 30, 2011, respectively. As at September 30, 2012, EEP had recorded total insurance recoveries of US$505 million ($74 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record receivables for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery to be probable.

Effective May 1, 2012, Enbridge renewed its comprehensive insurance program, through April 30, 2013, with a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability.

Legal and Regulatory Proceedings

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

Enbridge Income Fund

Proposed Crude Oil Storage and Renewable Energy Assets Transfer

In October 2012, Enbridge Income Fund Holdings Inc. (ENF) and the Fund announced they had entered into an agreement with Enbridge pursuant to which Enbridge would transfer five entities, which comprise crude oil storage in Alberta and renewable energy assets in Ontario, to the Fund. The agreement contemplates that Hardisty Contract Terminal, Hardisty Storage Caverns, Greenwich, and Amherstburg and Tilbury solar projects would be transferred for an aggregate price of approximately $1.2 billion, to be paid in part by the issuance of additional ordinary trust units of the Fund to ENF and additional Enbridge Commercial Trust preferred units to Enbridge. Under the agreement, Enbridge has agreed to provide bridge debt financing to the Fund for the balance of the price. The transaction is subject to all necessary approvals, including approval by the minority shareholders of ENF, as well as regulatory approval. If approved, and upon repayment of the bridge financing, the transaction is expected to provide Enbridge $0.8 billion of net funding for its large growth capital investment program.

Saskatchewan System Shipper Complaint

On December 17, 2010, the Saskatchewan System filed amended Westspur tariffs with the NEB with an effective date of February 1, 2011. In January 2011, a shipper on the Westspur System requested the NEB make the tolls interim effective February 1, 2011 pending discussions between the shipper and the Saskatchewan System on information requests put forward by the shipper. Subsequently, the shipper filed a complaint with the NEB on the basis the information provided by the Saskatchewan System was not adequate to allow for an assessment to be made of the reasonableness of the tolls. Six parties have filed letters with the NEB supporting the shipper s complaint. The NEB directed additional discussion among the parties and, as of November 6, 2012, the Fund continues to review the structure of its tolls with shippers.

CORPORATE

Noverco

Noverco Inc. (Noverco) holds, directly and indirectly, an investment in Enbridge common shares. In early 2012, Noverco advised Enbridge the substantial increase in the value of these shares over the last decade resulted in a significant shift in the balance of Noverco s asset mix. The Board of Noverco authorized the Caisse de Depot et Placement de Quebec, as manager of Noverco, to sell a portion of its Enbridge common share holding and rebalance Noverco s asset mix. On March 22, 2012, Noverco sold 22.5 million Enbridge common shares through a secondary offering. Enbridge s share of the proceeds of approximately $317 million was received as a dividend from Noverco on May 18, 2012 and was used to pay a portion of the Company s quarterly dividend on June 1, 2012. This portion of the quarterly dividend did not qualify for the enhanced dividend tax credit in Canada and accordingly, was not designated as an eligible dividend . For United States tax purposes, the dividend was a qualified dividend .

Preference Share Issuances

Since January 1, 2012, the Company has issued 92 million preference shares for gross proceeds of approximately $2,310 million with the following characteristics. See *Outstanding Share Data.*

	Gross Proceeds	Initial Yield	Dividend1	Per Share Base Redemption Value2	Redemption and Conversion Option Date2,3	Right to Convert Into3,4
(Canadian dollars, unless otherwise stated)						
Series F5	$500 million	4.0%	$1.00	$25	June 1, 2018	Series G
Series H5	$350 million	4.0%	$1.00	$25	September 1, 2018	Series I
Series J5	US$200 million	4.0%	US$1.00	US$25	June 1, 2017	Series K
Series L5	US$400 million	4.0%	US$1.00	US$25	September 1, 2017	Series M
Series N5	$450 million	4.0%	$1.00	$25	December 1, 2018	Series O
Series P5	$400 million	4.0%	$1.00	$25	March 1, 2019	Series Q

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

2 *The Company may at its option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.*

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

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.51% (Series G), 2.12% (Series I), 2.65% (Series O) or 2.50% (Series Q)); or US$25 x (number of days in quarter/365) x (90-day United States Government treasury bill rate + 3.05% (Series K) or 3.15% (Series M)).*

5 *See* Liquidity and Capital Resources Financing Activities *for dividends declared on October 24, 2012.*

Common Share Issuance

On June 8, 2012, the Company issued 9.83 million Common Shares for gross proceeds of approximately $400 million.

GROWTH PROJECTS COMMERCIALLY SECURED PROJECTS

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

			Actual/ Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)						
LIQUIDS PIPELINES						
1.		Edmonton Terminal Expansion	$0.3 billion	$0.1 billion	2012	Under construction
2.		Woodland Pipeline	$0.3 billion	$0.3 billion	2012	Substantially complete
3.		Wood Buffalo Pipeline	$0.4 billion	$0.3 billion	2012	Substantially complete
4.			$0.4 billion	$0.2 billion		

		Waupisoo Pipeline Capacity Expansion			2012-2013 (in phases)	Under construction
5.		Seaway Crude Pipeline System (including reversal, expansion and extension)	US$2.4 billion	US$1.3 billion	2012-2014 (in phases)	Under construction
6.		Norealis Pipeline	$0.5 billion	$0.2 billion	2013	Under construction
7.		Suncor Bitumen Blend	$0.2 billion	$0.1 billion	2013	Under construction
8.		Athabasca Pipeline Capacity Expansion	$0.4 billion	$0.2 billion	2013-2014 (in phases)	Under construction
9.		Eastern Access Expansion - Toledo expansion and Line 9 reversal3	US$0.2 billion + $0.3 billion	No significant expenditures to date	Toledo - 2013 Line 9 - 2013-2014	Pre-construction

9

		Actual/ Estimated Capital Cost1	Expenditures to Date2	Expected In-Service Date	Status
10.	Flanagan South Pipeline Project	US$2.8 billion	US$0.1 billion	2014	Pre-construction
11.	Canadian Mainline Expansion	$0.2 billion	No significant expenditures to date	2014	Pre-construction
12.	Athabasca Pipeline Twinning	$1.2 billion	No significant expenditures to date	2015	Pre-construction
GAS DISTRIBUTION					
13.	Greater Toronto Area Project	$0.6 billion	No significant expenditures to date	2016	Pre-construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES					
14.	Silver State North Solar Project4	US$0.2 billion	US$0.2 billion	2012	Complete
15.	Lac Alfred Wind Project	$0.3 billion	$0.2 billion	2012-2013 (in phases)	Under construction
16.	Cabin Gas Plant	$1.1 billion	$0.7 billion	To be determined	Deferred
17.	Peace River Arch Gas Development	$0.3 billion	No significant expenditures to date	2012-2013	Pre-construction
18.	Tioga Lateral Pipeline	US$0.1 billion	No significant expenditures to date	2013	Under construction
19.	Venice Condensate Stabilization Facility	US$0.2 billion	US$0.1 billion	2013	Under construction
20.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.1 billion	2014	Pre-construction
21.	Big Foot Oil Pipeline	US$0.2 billion	US$0.1 billion	2014	Pre-construction
SPONSORED INVESTMENTS					
22.	EEP - Bakken Expansion Program	US$0.4 billion	US$0.2 billion	2013	Under construction
23.	The Fund - Bakken Expansion Program	$0.2 billion	$0.1 billion	2013	Under construction
24.	EEP - Cushing Terminal Storage Expansion Project	US$0.2 billion	US$0.1 billion	2012-2013 (in phases)	Under construction
25.	EEP - South Haynesville Shale Expansion	US$0.3 billion	US$0.2 billion	2012+ (in phases)	Under construction
26.	EEP - Berthold Rail Project	US$0.1 billion	US$0.1 billion	2013	Under construction
27.	EEP - Ajax Cryogenic Processing Plant	US$0.2 billion	US$0.1 billion	2013	Under construction
28.	EEP - Bakken Access Program	US$0.1 billion	No significant expenditures to date	2013	Under construction
29.	EEP - Texas Express Pipeline	US$0.4 billion	US$0.1 billion	2013	Under construction
30.	EEP - Line 6B Replacement Program	US$0.3 billion	US$0.1 billion	2013	Under construction
31.	EEP - Eastern Access Expansion	US$2.2 billion	US$0.2 billion	2013-2014 (in phases)	Pre-construction
32.	EEP - Lakehead System Mainline Expansion	US$0.4 billion	No significant expenditures to date	2014	Pre-construction

10

Explanation of Responses:

				Actual/ Estimated Capital Cost1		Expenditures to Date2		Expected In-Service Date		Status
CORPORATE										
33.		Montana-Alberta Tie-Line		US$0.4 billion		US$0.3 billion		2013-2014 (in stages)		Under construction

1 These amounts are estimates only and subject to upward or downward adjustment based on various factors. As appropriate, the amounts reflect Enbridge s share of joint venture projects.

2 Expenditures to date reflect total cumulative expenditures incurred from inception of project up to September 30, 2012.

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

4 *Expenditures to date reflect total expenditures before receipt of US$0.1 billion payment from the United States Treasury. See* Growth Projects Commercially Secured Projects Gas Pipelines, Processing and Energy Services Silver State North Solar Project.

LIQUIDS PIPELINES

Edmonton Terminal Expansion

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

Woodland Pipeline

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

Wood Buffalo Pipeline

Enbridge entered into an agreement with Suncor Energy Inc. (Suncor) to construct a new, 95-kilometre (59-mile) 30-inch diameter crude oil pipeline, connecting the Athabasca Terminal adjacent to Suncor s oil sands plant to the Cheecham Terminal, which is the origin point of Enbridge s Waupisoo Pipeline. The Waupisoo Pipeline already delivers crude oil from several oil sands projects to the Edmonton, Alberta mainline hub. The new Wood Buffalo Pipeline parallels the existing Athabasca Pipeline between the Athabasca and Cheecham Terminals. The estimated capital cost remains at approximately $0.4 billion, with expenditures to date of approximately $0.3 billion. Although construction was completed and the new pipeline entered service in October 2012, additional expenditures on testing and site restoration will continue to be incurred into 2013.

Waupisoo Pipeline Capacity Expansion

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

Seaway Crude Pipeline System

Acquisition of Interest

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

Including the acquisition of the 50% interest in the Seaway Pipeline, Enbridge s total expected cost for the Seaway Crude Pipeline System is approximately US$2.4 billion. The joint Enbridge and Enterprise project, which consists of a reversal, an expansion and an extension, is expected to cost approximately US$1.2 billion, with expenditures incurred to date of approximately US$0.1 billion. Each of these components is discussed below.

Reversal

In December 2011, Enbridge and Enterprise announced plans to reverse the flow direction of the Seaway Pipeline, enabling it to transport crude oil from the oversupplied hub in Cushing, Oklahoma to the United States Gulf Coast. Included in the project scope is a 105-kilometre (65-mile), 36-inch new-build lateral from the Seaway Jones Creek facility southwest of Houston, Texas into Enterprise s ECHO crude oil terminal (ECHO Terminal) southeast of Houston. The reversal of the pipeline and acceptance of first crude was completed in May 2012, providing initial capacity of 150,000 bpd. Following pump station additions and modifications, which are expected to be completed in the first quarter of 2013, capacity is anticipated to increase to approximately 400,000 bpd depending upon the mix of light and heavy grades of crude oil.

Expansion and Extension

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

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

South Cheecham Rail and Truck Terminal

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

Norealis Pipeline

In order to provide pipeline and terminaling services to the proposed Husky-operated Sunrise Oil Sands Project, the Company is undertaking construction of a new originating terminal (Norealis Terminal), a 112-kilometre (66-mile) 24-inch diameter pipeline (Norealis Pipeline) from the Norealis Terminal to the Cheecham Terminal and additional tankage at Cheecham. The estimated cost of the project is approximately $0.5 billion, with expenditures to date of approximately $0.2 billion. With regulatory approval received in the second quarter of 2011, the project is expected to be in service in late 2013.

Suncor Bitumen Blend

In September 2012, Enbridge entered into an agreement with Suncor for a Bitumen Blend project, which includes the construction of a new 350,000 barrel tank, new blend and diluent lines and pumping capacity to connect with Suncor s lines just outside Enbridge s Athabasca Tank Farm. These new facilities will enable Suncor to transport blended bitumen volumes from its Firebag production into the Wood Buffalo pipeline. The estimated cost for the project is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion and in-service expected in the second quarter of 2013.

Athabasca Pipeline Capacity Expansion

The Company is undertaking an expansion of its Athabasca Pipeline to its full capacity to accommodate additional contractual commitments, including incremental production from the Christina Lake Oilsands Project operated by Cenovus Energy. This expansion is expected to increase the capacity of the Athabasca Pipeline to its maximum capacity of approximately 570,000 bpd, depending on the mix of crude oil types. The estimated cost of full expansion is approximately $0.4 billion, with expenditures to date of approximately $0.2 billion and an expected in-service date in the first quarter of 2013, for an initial 430,000 bpd of capacity. The balance of additional capacity is expected to be available by early 2014. The Athabasca Pipeline transports crude oil from various oil sands projects to the mainline hub at Hardisty, Alberta.

Flanagan South Pipeline Project

The 950-kilometre (590-mile) Flanagan South Pipeline will have an initial capacity of 585,000 bpd to transport crude oil from the Company s terminal at Flanagan, Illinois to Cushing, Oklahoma. The 36-inch diameter pipeline will be installed adjacent to the Company s Spearhead Pipeline for the majority of the route. Subject to regulatory and other approvals, the pipeline is expected to be in service by mid-2014. The estimated cost of the project is approximately US$2.8 billion, with expenditures to date of approximately US$0.1 billion.

Canadian Mainline Expansion

In May 2012, Enbridge announced an estimated $0.2 billion expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The current scope of the project involves the addition of pumping horsepower sufficient to raise the capacity of the Canadian mainline by 120,000 bpd to a capacity of 570,000 bpd and is expected to be in service by mid-2014. The expansion remains subject to NEB approval.

Athabasca Pipeline Twinning

This project involves the twinning of the southern section of the Company s Athabasca Pipeline from Kirby Lake, Alberta to the Hardisty, Alberta crude oil hub to provide additional capacity to serve expected oil sands growth in the Kirby Lake producing region. The expansion project, with an estimated cost of approximately $1.2 billion, will include 345 kilometres (210 miles) of 36-inch pipeline adjacent to the existing Athabasca Pipeline right-of-way. The initial annual capacity of the pipeline will be approximately 450,000 bpd, with expansion potential to 800,000 bpd. Subject to regulatory and other approvals, the line is expected to enter service in 2015.

GAS DISTRIBUTION

Greater Toronto Area Project

In September 2012, EGD announced plans to expand its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and continue the safe and reliable delivery of natural gas to current and future customers. At an expected cost of up to $0.6 billion, the proposed GTA project will consist of two segments of pipeline and related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. Subject to Ontario Energy Board approval, construction is targeted to start in 2014, with an expected completion in early 2016.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Silver State North Solar Project

In March 2012, Enbridge acquired a 100% interest in the development of the 50-megawatt (MW) Silver State North Solar Project (Silver State), located 65 kilometres (40 miles) south of Las Vegas, Nevada. The project, which began commercial operation in May 2012, was constructed under a fixed-price engineering, procurement and construction agreement with First Solar. First Solar is providing operations and maintenance services under a long-term contract. Energy output is being delivered to NV Energy, Inc. under a 25-year power purchase agreement (PPA). The Company s total investment in the project was approximately US$0.2 billion. In October 2012, the Company received a US$0.1 billion payment from the United States Treasury under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property.

Lac Alfred Wind Project

Enbridge secured a 50% interest in the development of the 300-MW Lac Alfred Wind Project (Lac Alfred), located 400 kilometres (250 miles) northeast of Quebec City in Quebec s Bas-Saint-Laurent region. The project is being constructed under a fixed price, turnkey, engineering, procurement and construction agreement and will take place in two phases: Phase 1 is expected to be completed in December 2012; while Phase 2 is expected to be completed in December 2013. Hydro-Quebec will purchase the power under a 20-year PPA and will construct the 30-kilometre transmission line to connect Lac Alfred to the grid under an interconnection agreement. The Company s total investment in the project is expected to be approximately $0.3 billion, with expenditures to date of approximately $0.2 billion.

Cabin Gas Plant

In 2011, the Company secured a 71% interest in the development of the Cabin Gas Plant (Cabin), located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin. The Company s total investment in phases 1 and 2 of Cabin was expected to be approximately $1.1 billion, with expenditures to date of approximately $0.7 billion. In October 2012, the Company and its partners announced plans to defer the commissioning of Phase 1 and the construction of Phase 2. Commencing in December 2012, Enbridge expects to begin receiving fees for its investment made to date in both Phases 1 and 2 of Cabin.

Peace River Arch Gas Development

In October 2012, the Company agreed, subject to finalization of definitive agreements, to acquire from Encana Corporation (Encana) certain sour gas gathering and compression facilities. These facilities, which are either currently in service or under construction, are located in the Peace River Arch (PRA) region of northwest Alberta. Closing of the transaction is scheduled for December 2012. Following the completion of construction in 2013, Enbridge s investment in the PRA Gas Development is expected to be approximately $0.3 billion. Enbridge is also working exclusively with Encana on facility scoping for development of additional major midstream facilities in the liquids-rich PRA region, which is expected to grow significantly in the years to come. Financial terms of the PRA Gas Development are expected to parallel previously established terms of the Cabin development.

Tioga Lateral Pipeline

Alliance Pipeline US is constructing a natural gas pipeline lateral and associated facilities to connect production from the Hess Tioga field processing plant in the Bakken region of North Dakota to the Alliance mainline near Sherwood, North Dakota. Through its 50% ownership interest in Alliance Pipeline US, Enbridge s expected cost related to the project is approximately US$0.1 billion. In October 2012, Alliance Pipeline US executed a contract with Hess Corporation (Hess), as an anchor shipper on the Tioga Lateral Pipeline. Aux Sable Liquids Products (Aux Sable) and Hess have reached a concurrent agreement for the provision of NGL services. The 124-kilometre (77-mile) Tioga Lateral Pipeline will facilitate movement of liquids-rich natural gas to NGL processing facilities owned by Aux Sable at the terminus of the Alliance mainline system. The pipeline will have an initial design capacity of approximately 106 million cubic feet per day (mmcf/d), which can be expanded based on shipper demand. Regulatory approval from FERC was received on September 20, 2012 and construction commenced early October 2012, with an expected in-service date of mid-2013.

Venice Condensate Stabilization Facility

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

Walker Ridge Gas Gathering System

The Company executed definitive agreements in 2010 with Chevron USA, Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge will construct, own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the proposed Jack, St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 meters (7,000 feet) with capacity of 0.1 billion cubic feet per day. WRGGS is expected to be in service in 2014 and is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.1 billion.

Big Foot Oil Pipeline

The Company executed definitive agreements in 2011 with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc. to construct and operate a 64-kilometre (40-mile) 20-inch oil pipeline with capacity of 100,000 bpd from the proposed Big Foot ultra-deep water 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, with expenditures to date of approximately US$0.1 billion, and it is expected to be in service in 2014.

SPONSORED INVESTMENTS

Bakken Expansion Program

A joint project to further expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in Montana, North Dakota, Saskatchewan and Manitoba is being undertaken by EEP and the Fund. The Bakken Expansion Program is expected to provide capacity of 145,000 bpd. The Bakken Expansion Program involves 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, with expenditures to date of approximately US$0.2 billion. In Canada, NEB approval was secured in December 2011 and expenditures to date are approximately $0.1 billion. The Bakken Expansion Program is expected to be completed in the first quarter of 2013.

Enbridge Energy Partners, L.P.

Cushing Terminal Storage Expansion Project

EEP is constructing 13 new storage tanks at its Cushing Terminal with an approximate shell capacity of 4.4 million barrels. To date, 11 tanks have been completed and placed into service, with the remaining two tanks expected to come into service by December 2012.

In July 2012, engineering design commenced on an additional three new tanks and associated infrastructure totaling 936,000 barrels of incremental shell capacity at EEP s Cushing Terminal, at an estimated cost of US$39 million. The expected in-service date for the three tanks is August 2013. The total estimated cost to construct the 16 storage tanks and infrastructure, as required, is approximately US$0.2 billion, with expenditures to date of approximately US$0.1 billion.

South Haynesville Shale Expansion

EEP is expanding its East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage. The expansion, completed in the second quarter of 2012 at an approximate cost of US$0.1 billion, increased capacity of EEP s East Texas system by 900 mmcf/d.

EEP plans to invest an additional US$0.2 billion, with expenditures to date of approximately US$0.1 billion, to expand its East Texas system, including the construction of gathering and related treating facilities. EEP has signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville shale to provide gathering, treating and transmission services. Completion of the additional expansion is dependent on drilling plans of these producers. Due to lower levels of producer activity in light of weak gas prices, EEP has deferred portions of its Haynesville natural gas expansion pending increases in drilling activity.

Berthold Rail Project

EEP is proceeding with the Berthold Rail Project, a US$0.1 billion investment that will provide an interim solution to shipper needs in the Bakken region. The project will expand capacity into the Berthold Terminal by 80,000 bpd and includes the construction of a three-unit train loading facility, crude oil tankage and other terminal facilities adjacent to existing infrastructure. The first phase of terminaling facilities was completed in September 2012, providing an additional capacity of 10,000 bpd to the Berthold Terminal. The loading facility and crude oil tankage are expected to be placed into service in the first quarter of 2013. Project expenditures to date are approximately US$0.1 billion.

Ajax Cryogenic Processing Plant

EEP is constructing an additional processing plant and other facilities on its Anadarko System at an approximate cost of US$0.2 billion, with expenditures to date of approximately US$0.1 billion. The Ajax Plant, with a planned capacity of 150 mmcf/d, is now expected to be in service mid-2013. When operational, the Ajax Plant in conjunction with the Allison Plant, is expected to increase total processing capacity on the Anadarko System to approximately 1,200 mmcf/d.

Bakken Access Program

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

Texas Express Pipeline

The Texas Express Pipeline (TEP) is a joint venture with Enterprise, Anadarko Petroleum Corporation and DCP Midstream LLC to design and construct a new NGL pipeline, as well as two new NGL gathering systems which EEP will build and operate. EEP will invest approximately US$0.4 billion in the TEP, which will originate in Skellytown, Texas and extend approximately 935 kilometres (580 miles) to NGL fractionation and storage facilities in Mont Belvieu, Texas. Expenditures to date are approximately US$0.1 billion. TEP is expected to have an initial capacity of approximately 280,000 bpd and will be expandable to approximately 400,000 bpd. Approximately 250,000 bpd of capacity has been subscribed on the pipeline.

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

Line 6B Replacement Program

This program includes the replacement of 120 kilometres (75 miles) of non-contiguous sections of Line 6B of EEP s Lakehead System. The Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. The new segments are now targeted to be placed in service during 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through EEP s tariff surcharge that is part of the system-wide rates of the Lakehead System. The total capital for this replacement program is estimated to be US$0.3 billion, with expenditures to date of approximately US$0.1 billion.

Eastern Access Expansion

As previously announced in 2011, Enbridge and EEP will undertake two projects to provide increased access to refineries in the United States upper mid-west and in Ontario for light crude oil produced in western Canada and the United States. One project involves the expansion of EEP s Line 5 light crude oil line between Superior, Wisconsin and Sarnia, Ontario by 50,000 bpd, at a cost of approximately US$0.1 billion. Complementing the Line 5 expansion, Enbridge plans to reverse a portion of its Line 9 (Line 9A) in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario at a cost of approximately $20 million. The Line 5 expansion is targeted to be in service during the first quarter of 2013 and, with NEB approval received in July 2012, the Line 9A reversal is expected to be in service in late 2013.

In May 2012, Enbridge announced that it had secured commercial support to proceed with additional Eastern Access projects. Enbridge and EEP also expect to proceed with supporting expansions of the United States mainline system between Flanagan, Illinois and Sarnia, Ontario. The additional Eastern Access projects include an 80,000 bpd expansion of Enbridge s Toledo Pipeline (Line 17), which connects with the Enbridge mainline at Stockbridge, Michigan and serves refineries at Toledo, Ohio and Detroit, Michigan, and a reversal of Enbridge s 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in Quebec. Sufficient capacity has been requested by refineries seeking to secure access to ample crude oil supplies from western Canada and the Bakken region in North Dakota to warrant proceeding with the project. The Eastern Access Line 9B reversal remains subject to NEB regulatory approval.

The Toledo Pipeline expansion is now expected to be available for service by the second quarter of 2013 at a cost of approximately US$0.2 billion. The Line 9B reversal is now expected to be available for service by mid-2014 at a cost of approximately $0.3 billion. Both the Toledo Pipeline and Line 9 assets are included in the Company s Liquids Pipelines segment.

The supporting mainline expansions include expansion of the Spearhead North pipeline (Line 62) between Flanagan and Griffith, Indiana, an additional 330,000 barrel tank at Griffith and the replacement of additional sections of Line 6B in Indiana and Michigan not already scheduled for replacement as previously announced. The capacity of Spearhead North will increase by 105,000 bpd and the capacity of Line 6B will increase by 260,000 bpd. The expected cost of the mainline expansions is US$2.2 billion, including the US$0.1 billion cost of the previously announced Line 5 expansion, with expenditures to date of approximately US$0.2 billion. In addition, the supporting mainline expansions will be funded 60% by Enbridge and 40% by EEP, with EEP having the option to reduce its funding and associated economic interest in the projects by up to 15% before the end of 2012. Furthermore, within one year of the in-service date, scheduled for early 2014, EEP will also have the option to increase its economic interest held at that time by up to 15%.

Lakehead System Mainline Expansion

In May 2012, EEP announced several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States border, near Neche, North Dakota, to Flanagan, Illinois. The current scope of the projects includes expansion of the Alberta Clipper line between the border and Superior, Wisconsin from 450,000 bpd to 570,000 bpd, and expansion of the Southern Access line between Superior and Flanagan, Illinois from 400,000 bpd to 560,000 bpd. The projects require only the addition of pumping horsepower and crude oil tanks at existing sites with no pipeline construction. Alberta Clipper and Southern Access are both held in Enbridge Energy, Limited Partnership (EELP), which will be fully funded by EEP for the cost of the expansions. The scope of the expansions remains under discussion, which could lead to an upward revision to capacity and cost.

17

Subject to finalization of scope and regulatory and shipper approvals, the expansions will be undertaken by EELP on a full cost-of-service basis, and are expected to be available for service in mid-2014 at an estimated cost of US$0.4 billion. The expansions are designed to accommodate increased throughput on the Lakehead System for deliveries to certain of Enbridge s pipelines, as well as growth in Chicago area refinery requirements. These expansions are incremental to those undertaken as part of the Eastern Access expansion.

CORPORATE

Montana-Alberta Tie-Line

Montana-Alberta Tie-Line (MATL) is a 345-kilometre (215-mile) transmission line from Great Falls, Montana to Lethbridge, Alberta, designed to take advantage of the growing supply of electric power in Montana and buoyant power demand in Alberta. The total expected cost for both the first 300-MW phase of MATL and the expansion for an additional 300-MW has been increased to approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion. While the permits required for construction have been obtained, the Alberta Utility Commission s approval in Canada is currently being updated to reflect a number of design modifications. Subject to this approval, the system s north-bound capacity, which is fully contracted, is now expected to be in service in the second quarter of 2013, with the expansion expected to be completed by the end of 2014.

Neal Hot Springs Geothermal Project

The Company has partnered with U.S. Geothermal Inc. (U.S. Geothermal) to develop the 35-MW (22-MW, net) Neal Hot Springs Geothermal Project located in Malheur County, Oregon. U.S. Geothermal is constructing the plant and will operate the facility. Completion of the project has been extended to the end of 2012 and, once operational, the facility will deliver electricity to the Idaho Power grid under a 25-year PPA. Enbridge will invest up to approximately US$33 million for a 41% interest in the project.

GROWTH PROJECTS OTHER PROJECTS UNDER DEVELOPMENT

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

LIQUIDS PIPELINES

Woodland Pipeline Extension

In September 2012, Enbridge received approval from the Alberta Energy Resources Conservation Board to construct the Woodland Pipeline Extension Project. The project will extend the Woodland Pipeline south from Enbridge s Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 385-kilometre (228-mile), 36-inch diameter pipeline, requiring an investment of approximately $1.0 billion to $1.4 billion for an initial capacity of 400,000 bpd, expandable to 800,000 bpd. The estimated investment remains subject to finalization of scope and a definitive cost estimate. More than 95% of the proposed route of the Woodland Pipeline Extension follows existing Enbridge right-of-way and will generally follow the existing Waupisoo Pipeline. The project will also include new pump stations at the existing Roundhill Station location and at the Cheecham Terminal. All major environmental and regulatory approvals have been received, and subject to final commercial approval, Enbridge anticipates a 2015 in-service date. Project expenditures to date are approximately $0.1 billion and pre-development costs are being backstopped by shippers pending final commercial approval.

Northern Gateway Project

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

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

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

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

In a Procedural Direction issued in December 2011, the JRP indicated community hearings would be scheduled so the Panel would hear all oral evidence from registered intervenors first, followed by oral statements from registered participants. Community hearings for oral evidence and statements took place between January and August 2012 in various communities. A written record of what was said each day in the community hearings is available on the Panel s website. Intervenors responded to questions by Northern Gateway on July 6, 2012. Northern Gateway filed reply evidence to the evidence of the intervenors on July 20, 2012. The final hearings commenced on September 4, 2012 where Northern Gateway, intervenors, government participants and the JRP will question those who have presented oral or written evidence.

The final hearings and the remaining oral statements from interested parties who do not reside along the pipeline corridor or shipping routes are expected to be completed by April 2013. Based on this projected schedule, the JRP expects to issue its reports and findings on the proposed project by December 2013. Of the 45 Aboriginal groups eligible to participate as equity owners, 26 have signed up to do so. Subject to continued commercial support, regulatory and other approvals, and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company currently estimates that Northern Gateway could be in service in 2018 at the earliest. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.3 billion, of which approximately half is secured in funding from Western Canada producers and Pacific Rim refiners toward the costs of seeking the necessary regulatory approvals for the project. Given the many uncertainties surrounding the Northern Gateway Project, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

On February 23, 2012, Transport Canada published its TERMPOL Review Process Report of the Northern Gateway Project s proposed marine operations. Transport Canada has filed the results of the study with the federal JRP tasked with assessing the project. The study reviewed the marine operations associated with the Northern Gateway terminal and associated tanker traffic in Canadian waters. The review concluded that: While there will always be residual risk in any project, after reviewing the proponent s studies and taking into account the proponent s commitments, no regulatory concerns have been identified for the vessels, vessel operations, the proposed routes, navigability, other waterway users and the marine terminal operations associated with vessels supporting the Northern Gateway Project. The TERMPOL report was prepared and approved by Canadian government authorities including Transport Canada; Environment Canada; Fisheries and Oceans Canada; Canadian Coast Guard; and Pacific Pilotage Authority Canada. Further review of the Northern Gateway application by the JRP, as well as other agencies, is ongoing.

As noted above, Northern Gateway filed reply evidence with the JRP on July 20, 2012 which contained details of further enhancements in pipeline design and operations. These extra measures, estimated to cost an additional $400 million to $500 million, together with additional marine infrastructure, result in a total estimated project cost of approximately $6.6 billion. The enhancements include: increasing pipeline wall thickness of the oil pipeline; additional pipeline wall thickness for water crossings such as major tributaries to the Fraser, Skeena and Kitimat Rivers; increasing the number of remotely-operated isolation valves by 50% within British Columbia to protect high-value fish habitat; increasing frequency of in-line inspection surveys across the entire

Northern Gateway pipeline system by a minimum of 50% over and above current standards; installing dual leak detection systems; and staffing pump stations in remote

19

locations on a 24 hour / 7 day basis for on-site monitoring, heightened security and rapid response to abnormal conditions.

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

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Heidelberg Lateral Pipeline

In November 2012, Enbridge announced it will build, own and operate a crude oil pipeline in the Gulf of Mexico to connect the proposed Heidelberg development, operated by Anadarko Petroleum Corporation (Anadarko), to an existing third-party system. The Heidelberg lateral, which will be 20 inches in diameter and approximately 55 kilometres (34 miles) in length, will originate in Green Canyon Block 860, approximately 320 kilometres (200 miles) southwest of New Orleans and in an estimated 1,600 metres (5,300 feet) of water. Subject to finalization of definitive agreements and sanction of the development by Anadarko and its project co-owners, the lateral pipeline is expected to be operational by 2016.

Nexus Gas Transmission Project

In September 2012, Enbridge, DTE Energy and Spectra Energy Corp (Spectra) announced the execution of a Memorandum of Understanding to jointly develop the Nexus Gas Transmission (Nexus) system, a project that will move growing supplies of Ohio Utica shale gas to markets in the United States midwest, including Ohio and Michigan, and Ontario, Canada. The proposed Nexus project will originate in northeastern Ohio, include approximately 400 kilometres (250 miles) of large diameter pipe, and be capable of transporting one billion cubic feet per day of natural gas. The line will follow existing utility corridors to an interconnect in Michigan and utilize the existing Vector Pipeline system to reach the Ontario market. Upon completion, Spectra will become a 20% owner in Vector Pipeline, a joint venture between DTE Energy and Enbridge. An open season was launched October 15, 2012 and the targeted in-service date is late 2016, depending on final market demand and contract commitments.

FINANCIAL RESULTS

LIQUIDS PIPELINES

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Canadian Mainline	**120**	101	**315**	264
Regional Oil Sands System	**31**	28	**81**	81
Southern Lights Pipeline	**16**	18	**53**	54
Seaway Pipeline	**11**	-	**13**	-

Spearhead Pipeline	**8**	4	**30**	14
Feeder Pipelines and Other	**5**	(1)	**9**	(3)
Adjusted earnings	**191**	150	**501**	410
Canadian Mainline - shipper dispute settlement	**-**	-	**-**	14
Canadian Mainline - Line 9 tolling adjustment	**-**	(3)	**6**	10
Canadian Mainline - unrealized derivative fair value gains/(loss)	**90**	(180)	**83**	(134)
Spearhead Pipeline - unrealized derivative fair value gains/(loss)	**(1)**	1	**-**	1
Feeder Pipelines and Other - unrealized derivative fair value gains	**-**	1	**-**	1
Earnings/(loss) attributable to common shareholders	**280**	(31)	**590**	302

Canadian Mainline

Since July 1, 2011, Canadian Mainline earnings are governed by the CTS, with the exception of Lines 8 and 9 that remain under a cost of service model. Prior to that, Canadian Mainline tolls were governed by a series of agreements, the most significant being the Incentive Tolling Settlement applicable to the

20

mainline system and the Terrace and Alberta Clipper agreements. CTS tolls are not adjusted for volumes or operating costs; therefore, variations in these drivers cause variability in earnings. Canadian Mainline revenues increased by 13% to $355 million for the three months ended September 30, 2012 compared with the same period of 2011. This increase was primarily due to increased volumes and a higher Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll which, under the IJT, is impacted by changes in the Lakehead System Local Toll. Higher revenues were partially offset by higher operating and administrative costs, primarily due to higher employee related costs and higher leak repairs. Incremental oil sands crude production in Alberta and strong production growth out of the Bakken in North Dakota have bolstered supply to midwest markets and placed increased downward pressure on crude oil prices in this market. Enbridge believes this pressure will at least be partially reduced upon completion of its market access projects. This discounted crude oil, coupled with strong refining margins, is increasing demand in the midwest for Canadian and Bakken crude oil supply and driving increased long haul barrels on Canadian Mainline and EEP s Lakehead System.

Supplemental information on Canadian Mainline adjusted earnings is as follows:

	Three months ended September 30,		Nine months ended September 30,[1]
	2012	2011	**2012**
(millions of Canadian dollars)			
Revenues	**355**	314	**1,011**
Expenses			
Operating and administrative	**93**	88	**283**
Power	**31**	28	**86**
Depreciation and amortization	**54**	53	**163**
	178	169	**532**
	177	145	**479**
Other income/(expense)	**(3)**	3	**(6)**
Interest expense	**(36)**	(32)	**(101)**
	138	116	**372**
Income taxes	**(18)**	(15)	**(57)**
Adjusted earnings	**120**	101	**315**
Effective United States to Canadian dollar exchange rate[2]	**0.975**	0.989	**0.970**

	Three months ended September 30,	
	2012	2011
IJT Benchmark Toll[3] *(United States dollars per barrel)*	**$3.94**	$3.85
Lakehead System Local Toll[4] *(United States dollars per barrel)*	**$1.85**	$2.01
Canadian Mainline IJT Residual Benchmark Toll[5] *(United States dollars per barrel)*	**$2.09**	$1.84

1 *Comparative figures for the nine months ended September 30, 2011 are not applicable as CTS first took effect July 1, 2011.*

2 *Inclusive of realized gains or losses on foreign exchange derivative financial instruments.*

3 *The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2012, the IJT benchmark toll increased from US$3.85 to US$3.94.*

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

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

21

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
Throughput volume[1] *(thousand barrels per day (kbpd))*	**1,617**	1,565	**1,654**	1,541

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

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

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

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

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

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

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

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

Regional Oil Sands System

Regional Oil Sands System earnings for the three months ended September 30, 2012 increased primarily as a result of higher shipped volumes and increased tolls on certain laterals, as well as higher earnings from annual escalation in storage and terminaling fees. These increases were partially offset by higher operating and administrative expenses.

Seaway Pipeline

Seaway Pipeline earnings reflected operating earnings since the completion of the reversal in May 2012.

Spearhead Pipeline

Spearhead Pipeline adjusted earnings increased as a result of higher volumes and tolls, partially offset by higher operating and administrative costs, including power and repairs and maintenance. Adjusted earnings for the full year also reflected higher earnings from make-up rights which expired in the period. In the third quarter, the recognition of expired make-up rights was lower in 2012 compared with 2011. Volumes significantly increased over 2011 due to increased demand at Cushing, Oklahoma in anticipation of additional capacity on the Seaway Pipeline for further transportation to the United States Gulf Coast.

Feeder Pipelines and Other

The increase in Feeder Pipelines and Other adjusted earnings was primarily a result of a higher contribution from Olympic Pipeline due to a tariff increase. Earnings for the full year also reflected higher volumes on Toledo Pipeline. In 2011, earnings from Toledo Pipeline were negatively impacted by integrity work on Lines 6A and 6B of EEP s Lakehead System.

Liquids Pipelines earnings were impacted by the following adjusting items.

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

- Feeder Pipelines and Other earnings/(loss) for 2011 included unrealized fair value gains on derivatives financial instruments related to allowance oil commodity prices.

23

GAS DISTRIBUTION

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Enbridge Gas Distribution (EGD)	**(17)**	(10)	**93**	97
Other Gas Distribution and Storage	**(1)**	6	**20**	28
Adjusted earnings/(loss)	**(18)**	(4)	**113**	125
EGD - colder/(warmer) than normal weather	**-**	-	**(24)**	13
EGD - tax rate changes	**-**	-	**(9)**	-
Earnings/(loss) attributable to common shareholders	**(18)**	(4)	**80**	138

The decrease in EGD s adjusted earnings for the three and nine months ended September 30, 2012 was primarily due to higher system integrity and operating and administrative costs as well as higher depreciation expense, partially offset by customer growth and lower interest expense.

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

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

- EGD earnings/(loss) are adjusted to reflect the impact of weather.
- Earnings from EGD for the nine months ended September 30, 2012 reflected the impact of unfavourable tax rate changes.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Enbridge Offshore Pipelines (Offshore)	**(1)**	(4)	**-**	(5)
Alliance Pipeline US	**6**	6	**18**	19
Vector Pipeline	**4**	4	**12**	13
Aux Sable	**21**	12	**47**	36
Energy Services	**9**	18	**31**	43
Other	**(3)**	5	**9**	16

Adjusted earnings	**36**	41	**117**	122
Aux Sable - unrealized derivative fair value gains/(loss)	**(8)**	4	**15**	(3)
Energy Services - unrealized derivative fair value gains/(loss)	**(232)**	1	**(558)**	30
Other - unrealized derivative fair value gains	**3**	-	**-**	-
Earnings/(loss) attributable to common shareholders	**(201)**	46	**(426)**	149

Compared with the prior period, Offshore earnings for 2012 included a higher transportation rate for volumes shipped on the Stingray Pipeline System, as well as a reduction in interest expense and a $2

24

million favourable impact related to the reversal of a shipper reserve pertaining to a rate case from 2011. Overall, Offshore is expected to be in a loss position for the full year as the Company continues to experience weak volumes due to delayed drilling programs and more scheduled production outages by producers in the Gulf of Mexico.

In 2012, Aux Sable adjusted earnings increased primarily due to stronger realized fractionation margins, as well as earnings contributions from new assets acquired in July 2011, including Prairie Rose Pipeline and the Palermo Conditioning Plant.

Energy Services operates a physical commodity marketing business which captures quality, time and location differentials when opportunities arise. To execute these strategies, Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines. Energy Services adjusted earnings for the three and nine months ended September 30, 2012 declined primarily due to changing market conditions which gave rise to fewer margin opportunities in liquids marketing.

The decrease in Other adjusted earnings was primarily due to the sale of Ontario Wind, Sarnia Solar and Talbot Wind energy projects (Renewable Assets) to the Fund in October 2011, as well as higher business development costs. These negative impacts were partially offset by positive contributions from Amherstburg Solar, which was completed in the third quarter of 2011, and from Cedar Point and Greenwich wind energy projects, which commenced commercial operations in the fourth quarter of 2011.

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

- Aux Sable earnings for each period reflected unrealized fair value changes on derivative financial instruments related to the Company s forward gas processing risk management position.
- Energy Services earnings/(loss) for each period reflected unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of forward transportation and storage transactions. A gain or loss on such a financial derivative corresponds to a similar but opposite loss or gain on the value of the underlying physical transaction which is expected to be realized in the future when the physical transaction settles. Unlike the change in the value of the financial derivative, the loss or gain on the value of the underlying physical transaction is not recorded for financial statement purposes until the periods in which it is realized.
- Other earnings for 2012 reflected unrealized fair value changes on derivative financial instruments.

SPONSORED INVESTMENTS

(millions of Canadian dollars)	Three months ended September 30, **2012**	2011	Nine months ended September 30, **2012**	2011
Enbridge Energy Partners (EEP)	**41**	41	**109**	106
Enbridge Energy, Limited Partnership - Alberta Clipper US (EELP)	**10**	10	**32**	32
Enbridge Income Fund (the Fund)	**18**	10	**55**	32
Adjusted earnings	**69**	61	**196**	170
EEP - NGL trucking and marketing investigation costs	**-**	-	**(1)**	-
EEP - unrealized derivative fair value gains/(loss)	**(6)**	8	**1**	8
EEP - leak insurance recoveries	**24**	13	**24**	21
EEP - leak remediation costs and lost revenue	**(7)**	(21)	**(9)**	(27)
EEP - shipper dispute settlement	**-**	-	**-**	8
EEP - lawsuit settlement	**-**	-	**-**	1
EEP - impact of unusual weather conditions	**-**	-	**-**	(1)
Earnings attributable to common shareholders	**80**	61	**211**	180

2012 adjusted earnings from the Company s investment in EEP included higher incentive income and strong results from the liquids business primarily due to higher average daily delivery volumes on all major liquids systems, as well as an increased contribution from storage terminal facilities that were placed into service during 2012. Earnings from the natural gas business decreased as a result of lower natural gas and NGL prices. An increase in operating and administrative costs, primarily workforce related costs, as well as higher interest expense also impacted EEP s 2012 adjusted earnings.

Earnings for the Fund for 2012 included earnings from the Renewable Assets acquired from a wholly-owned subsidiary of Enbridge in October 2011. Prior to October 2011, earnings from the Renewable Assets were presented within the Gas Pipelines, Processing and Energy Services segment. Earnings for the first nine months of 2012 also reflected the increase in the proportion of Enbridge s economic interest in the Fund s assets, which is held in the form of preference units, following the October 2011 Renewable Assets transfer. Partially offsetting strong contributions from the Renewable Assets were increased interest costs associated with funding the acquisition as well as higher deferred income taxes.

Sponsored Investment earnings were impacted by the following adjusting items.

- EEP earnings for 2012 reflected a charge for legal and accounting costs associated with an investigation at a NGL trucking and marketing subsidiary, which was concluded in the first quarter of 2012.
- Earnings from EEP included a change in the unrealized fair value on derivative financial instruments in each period.
- Earnings from EEP for 2011 included insurance recoveries associated with the Line 6B crude oil release. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Line 6A and 6B Crude Oil Releases.*
- Earnings from EEP for each period included charges, related to estimated costs, before insurance recoveries, associated with the Line 6A, 6B and Line 14 crude oil releases. See *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Line 14 Crude Oil Release* and *Recent Developments Sponsored Investments Enbridge Energy Partners, L.P. Lakehead System Line 6A and 6B Crude Oil Releases*.

- EEP earnings for 2011 included proceeds from the settlement of a shipper dispute related to oil measurement adjustments in prior years.

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

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

CORPORATE

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Noverco	**(3)**	(3)	**19**	14
Other Corporate	**(6)**	(6)	**(24)**	(14)
Adjusted loss	**(9)**	(9)	**(5)**	-
Noverco - equity earnings adjustment	**-**	-	**(12)**	-
Noverco - unrealized derivative fair value loss	**(11)**	-	**(11)**	-
Other Corporate - unrealized derivative fair value gains/(loss)	**89**	(83)	**32**	(132)
Other Corporate - foreign tax recovery	**-**	-	**29**	-
Other Corporate - unrealized foreign exchange gains/(loss) on translation of intercompany balances, net	**(17)**	6	**(17)**	23
Other Corporate - impact of tax rate changes	**(4)**	9	**(7)**	1
Earnings/(loss) attributable to common shareholders	**48**	(77)	**9**	(108)

Noverco adjusted earnings for the nine months ended September 30, 2012 reflected contributions from the Company s increased preferred share investment. The loss incurred in the third quarter reflected the inherent seasonality of Noverco s underlying gas distribution operations.

The increase in Other Corporate adjusted loss was primarily due to an increase in preference share dividends of $30 million in the third quarter and $64 million in the nine months ended September 30, 2012 compared with the corresponding periods of 2011. Since July 2011, the Company issued an additional 130 million preference shares for gross proceeds of approximately $3,260 million. See *Recent Developments Corporate Preference Share Issuances.* Although net Corporate segment financing costs decreased in the first nine months of 2012 compared with the corresponding period of 2011, this decrease was more than offset by the increase in preference share dividends and higher income taxes, resulting in an overall increase in Other Corporate adjusted loss.

Corporate costs were impacted by the following adjusting items.

- Noverco loss for the nine months ended September 30, 2012 included an unfavourable equity earnings adjustment related to prior periods.
- Noverco loss for 2012 reflected unrealized fair value losses on derivative financial instruments.
- Earnings/(loss) for each period included a change in the unrealized fair value gains and losses on derivative financial instruments related to forward foreign exchange risk management positions.
- Earnings for 2012 were impacted by taxes related to a historical foreign investment.
- 2011 losses included net unrealized foreign exchange gains and losses on the translation of foreign-denominated intercompany balances.
- Losses for 2011 were impacted by tax rate changes.

LIQUIDITY AND CAPITAL RESOURCES

The Company expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. The Company has also been active in the equity markets in the first nine months of 2012 to further bolster liquidity in support of the Company s capital expenditure program, issuing preference shares of approximately $2,245 million, net of issuance costs, and approximately $400 million in common equity. Further, in July 2012, the Company s subsidiary Enbridge Pipelines Inc. (EPI) issued a $100 million Century Bond with a 100-year term to maturity. In September 2012, EEP completed an offering of 16.1 million Class A common units for gross proceeds of US$447 million, inclusive of US$58 million for units issued pursuant to an overallotment option. EEP was also successful in securing a new US$675 million credit facility.

At September 30, 2012, excluding the Southern Lights project financing, the Company had $11,572 million of committed credit facilities of which $3,358 million were either drawn or allocated to backstop commercial paper. Inclusive of cash and cash equivalents, net of bank indebtedness, of $1,364 million, the Company had net available liquidity of $9,578 million at September 30, 2012. The net available liquidity, together with cash from operations and anticipated future access to capital markets, is expected to be sufficient to finance all currently secured capital projects and to provide flexibility for new investment opportunities.

The Company actively manages its bank funding sources to ensure adequate liquidity and to optimize pricing and other terms. The following table provides details of the Company s credit facilities at September 30, 2012.

	Maturity Dates[1]	Total Facilities	Credit Facility Draws[2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2014	**300**	**25**	**275**
Gas Distribution	2014	**712**	**580**	**132**
Sponsored Investments	2014-2017	**3,131**	**1,072**	**2,059**
Corporate	2013-2017	**7,429**	**1,681**	**5,748**
		11,572	**3,358**	**8,214**
Southern Lights project financing[3]	2014	**1,480**	**1,417**	**63**
Total credit facilities		**13,052**	**4,775**	**8,277**

1 *Total facilities include $35 million in demand facilities with no maturity date.*
2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
3 *Total facilities inclusive of $59 million for debt service reserve letters of credit.*

OPERATING ACTIVITIES

Cash provided by operating activities was $740 million and $2,372 million for the three and nine months ended September 30, 2012, respectively, compared with $689 million and $2,548 million for the three and nine months ended September 30, 2011. The most significant factor which impacted the decline in cash provided by operating activities for the nine months was changes in operating assets and liabilities. For the first nine months of 2012, changes in operating assets and liabilities contributed to a $429 million decline in cash compared with a $351 million increase in the same period of 2011. Working capital will fluctuate from time to time due to seasonal variations in customer receivable balances, natural gas inventory and borrowing levels at EGD, which in turn are impacted by weather and commodity prices, as well as timing of tax payments and general activity levels within the Company s Energy Services businesses, among others.

The working capital fluctuations were partially offset by the favourable operating performance of the Canadian Mainline under CTS, strong volumes across all of the Company s liquids pipelines assets and general cash growth from development projects placed in service in recent years. Additionally, in the second quarter of 2012 the Company received a $317 million one-time dividend from its investment in Noverco. In the first quarter of 2012 Noverco had realized a substantial gain on the disposition of a portion of its investment in Enbridge shares and subsequently distributed the proceeds from this transaction to its shareholders, by way of dividend, in May 2012.

There are no material restrictions on the Company s cash with the exception of restricted cash of $7 million related to Southern Lights project financing and cash in trust of $19 million for specific shipper commitments.

INVESTING ACTIVITIES

Cash used in investing activities for the three and nine months ended September 30, 2012 was $1,619 million and $4,022 million, respectively, compared with $917 million and $2,403 million for the three and nine months ended September 30, 2011. Cash used in investing activities for the nine months ended

September 30, 2012 included $3,536 million (2011 - $2,160 million) of additions to property, plant and equipment, primarily directed to the construction of the Company s growth projects, partially offset by the timing of cash payments of construction payables. Additionally, greater intangible asset additions, primarily software, and additional funding of various investments and joint ventures, namely TEP and the Woodland Pipeline, also contributed to the increased cash usage for 2012.

Investing activities for the nine months ended September 30, 2012 also included the Silver State acquisition that was completed in the first quarter of 2012, as well as the acquisition of the remaining 10% of Greenwich that was completed in the second quarter of 2012.

FINANCING ACTIVITIES

Cash generated from financing activities was $1,949 million and $2,670 million for the three and nine months ended September 30, 2012, respectively, compared with $766 and $595 million for the corresponding periods of 2011. The increase in cash provided by financing activities for the first nine months of 2012 was primarily due to the issuance of preference shares of $2,245 million, of which $827 million was issued in the third quarter of 2012. The Company also completed a common equity issuance of approximately $400 million during the second quarter of 2012. Additionally, the Company had a net issuance of debenture and term notes of $843 million during the nine months ended September 30, 2012. The Company accesses debt and equity markets as required to finance currently secured capital projects and to provide flexibility for new growth opportunities. In addition to capital markets activity, the Company had draws of short-term borrowings and bank indebtedness of $285 million, which was offset by repayments of commercial paper and credit facility draws of $692 million. Cash provided by financing activities for the nine months ended September 30, 2012 also included contributions, net of distributions, from third party investors in EEP of $136 million (2011 - $310 million), partially offset by distributions to the Fund public unitholders of $35 million (2011 - $22 million).

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 September 30, 2012, dividends declared were $225 million (2011 - $191 million), of which $150 million (2011 - $127 million) were paid in cash and reflected in financing activities. The remaining $75 million (2011 - $64 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the nine months ended September 30, 2012, dividends declared were $668 million (2011 - $569 million), of which $455 million (2011 - $387 million) were paid in cash and reflected in financing activities. The remaining $213 million (2011 - $182 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 nine months ended September 30, 2012, 33% (2011 - 34%) and 32% (2011 - 32%) of total dividends declared were reinvested.

On October 24, 2012, the Enbridge Board declared the following quarterly dividends. All dividends are payable on December 1, 2012 to shareholders of record on November 15, 2012.

Common Shares	$0.28250
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N[1]	$0.37530
Preference Shares, Series P[2]	$0.21640

1 *This first dividend declared for the Preference Shares, Series N includes accrued dividends from July 17, 2012, the date the shares were issued. The regular quarterly dividend of $0.25 per share will take effect on March 1, 2013. See* Recent Developments Corporate Preference Share Issuances.

2 *This first dividend declared for the Preference Shares, Series P includes accrued dividends from September 13, 2012, the date the shares were issued. The regular quarterly dividend of $0.25 per share will take effect on March 1, 2013. See* Recent Developments Corporate Preference Share Issuances.

Capital Expenditure Commitments

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,334 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

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

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

Foreign Exchange Risk

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

Interest Rate Risk

The Company s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2017 at an average swap rate of 2.18%.

The Company s earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2016. A total of $11,147 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.35%.

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

Commodity Price Risk

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

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

Equity Price Risk

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

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

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

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(28)**	57	**(19)**	15
Interest rate contracts	**(1)**	(560)	**(190)**	(545)
Commodity contracts	**(27)**	101	**54**	106
Other contracts	**(3)**	1	**(3)**	3
Net investment hedges				
Foreign exchange contracts	**34**	(88)	**16**	(63)
	(25)	(489)	**(142)**	(484)
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Cash flow hedges				
Foreign exchange contracts1	**2**	1	**1**	1
Interest rate contracts2	**(7)**	4	**17**	13
Commodity contracts3	**-**	(13)	**(3)**	(43)
Other contracts	**-**	-	**-**	(1)
	(5)	(8)	**15**	(30)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Cash flow hedges				
Interest rate contracts2	**(1)**	3	**3**	(6)
Commodity contracts3	**4**	(1)	**(1)**	-
	3	2	**2**	(6)
Non-qualifying derivatives				
Foreign exchange contracts1	**303**	(234)	**242**	(232)
Interest rate contracts2	**(1)**	1	**(2)**	5
Commodity contracts4	**(531)**	(56)	**(973)**	(3)
Other contracts5	**(2)**	9	**3**	9
	(231)	(280)	**(730)**	(221)

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all of the terms and conditions of its committed credit facilities at September 30, 2012. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

32

CREDIT RISK

Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company s credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

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

fair value measurements

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

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Since then, the NEB has issued several revised base case assumptions based on feedback from member companies. Companies have the option to follow the base case assumptions or to submit pipeline specific applications.

On November 29, 2011, as required by the NEB, the Company filed its estimated abandonment costs for its regulated pipeline systems within EPI and Enbridge Pipelines (NW) Inc. (Group 1 companies) and Enbridge Southern Lights GP Inc., Enbridge Bakken Pipeline Company Inc., Enbridge Pipelines (Westspur) Inc. and Vector Pipelines Limited Partnership (Group 2 companies).

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

Both of the required submissions will require NEB approval and will result in increased transportation tolls and regulatory liabilities. The specific toll impacts are uncertain at this time as the Company anticipates the NEB filings in late 2012 and early 2013 will go to hearing prior to NEB approval.

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

CHANGE IN ACCOUNTING POLICIES

UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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

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

FAIR VALUE MEASUREMENT

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

STATEMENT OF COMPREHENSIVE INCOME

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

GOODWILL IMPAIRMENT

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

34

Explanation of Responses:

QUARTERLY FINANCIAL INFORMATION

		2012[1]			2011[1]			2010[2]
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
(millions of Canadian dollars, except per share amounts)								
Revenues	**5,788**	5,718	6,627	7,237	6,277	6,938	6,529	4,193
Earnings attributable to common shareholders	**189**	11	264	159	(5)	302	364	326
Earnings per common share[3]	**0.24**	0.01	0.35	0.21	(0.01)	0.40	0.49	0.44
Diluted earnings per common share[3]	**0.24**	0.01	0.34	0.21	(0.01)	0.40	0.48	0.43
Dividends per common share[3]	**0.2825**	0.2825	0.2825	0.2450	0.2450	0.2450	0.2450	0.2125
EGD - warmer/(colder) than normal weather	**-**	-	24	12	-	(2)	(11)	(6)
Net unrealized derivative fair value and intercompany foreign exchange (gains)/loss	**76**	252	110	(241)	242	(18)	(18)	(71)

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

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

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

The Company actively manages its exposure to market price risks, including, but not limited to, commodity prices and foreign exchange rates. To the extent derivative instruments used to manage these risks are non-qualifying for the purposes of applying hedge accounting, unrealized fair value gains and losses on these instruments will impact earnings. The revaluation of foreign-denominated intercompany loans also impacted earnings in 2011.

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

In addition to the impacts of weather in EGD s franchise area and unrealized gains and losses outlined above, the following significant items impacted the Company s quarterly earnings.

• Reflected in earnings is the Company s share of leak remediation costs and lost revenue associated with the Line 6A, Line 6B and Line 14 crude oil releases. For the second and third quarters of 2012, these amounts were $2 million and $7 million (2011 - $6 million and $21 million), respectively. An amount of $6 million (2010 - $21 million) was recognized in the fourth quarter of 2011. Earnings also reflected insurance recoveries associated with the Line 6B crude oil release of $24 million in the third quarter of 2012 and $5 million, $3 million, $13 million and $29 million in the first, second, third and fourth quarters of 2011, respectively.

35

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

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

NON-GAAP RECONCILIATION

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Earnings/(loss) attributable to common shareholders	**189**	(5)	**464**	661
Significant after-tax non-recurring or non-operating factors and variances:				
Liquids Pipelines				
Canadian Mainline - shipper dispute settlement	**-**	-	**-**	(14)
Canadian Mainline - Line 9 tolling adjustment	**-**	3	**(6)**	(10)
Canadian Mainline - unrealized derivative fair value (gains)/loss	**(90)**	180	**(83)**	134
Spearhead Pipeline - unrealized derivative fair value (gains)/loss	**1**	(1)	**-**	(1)
Feeder Pipelines and Other - unrealized derivative fair value gains	**-**	(1)	**-**	(1)
Gas Distribution				
EGD - (colder)/warmer than normal weather	**-**	-	**24**	(13)
EGD - tax rate changes	**-**	-	**9**	-
Gas Pipelines, Processing and Energy Services				
Aux Sable - unrealized derivative fair value (gains)/loss	**8**	(4)	**(15)**	3
Energy Services - unrealized derivative fair value (gains)/loss	**232**	(1)	**558**	(30)
Other - unrealized derivative fair value gains	**(3)**	-	**-**	-
Sponsored Investments				
EEP - NGL trucking and marketing investigation costs	**-**	-	**1**	-
EEP - unrealized derivative fair value (gains)/loss	**6**	(8)	**(1)**	(8)
EEP - leak insurance recoveries	**(24)**	(13)	**(24)**	(21)
EEP - leak remediation costs and lost revenue	**7**	21	**9**	27
EEP - shipper dispute settlement	**-**	-	**-**	(8)
EEP - lawsuit settlement	**-**	-	**-**	(1)
EEP - impact of unusual weather conditions	**-**	-	**-**	1
Corporate				
Noverco - equity earnings adjustment	**-**	-	**12**	-
Noverco - unrealized derivative fair value loss	**11**	-	**11**	-
Other Corporate - unrealized derivative fair value (gains)/loss	**(89)**	83	**(32)**	132
Other Corporate - foreign tax recovery	**-**	-	**(29)**	-
Other Corporate - unrealized foreign exchange (gains)/loss on translation of intercompany balances, net	**17**	(6)	**17**	(23)
Other Corporate - impact of tax rate changes	**4**	(9)	**7**	(1)
Adjusted earnings	**269**	239	**922**	827

Explanation of Responses:

OUTSTANDING SHARE DATA[1]

	Number
Preference Shares, Series A[2]	5,000,000
Preference Shares, Series B[2,3]	20,000,000
Preference Shares, Series D[2,4]	18,000,000
Preference Shares, Series F[2,5]	20,000,000
Preference Shares, Series H[2,6]	14,000,000
Preference Shares, Series J[2,7]	8,000,000
Preference Shares, Series L[2,8]	16,000,000
Preference Shares, Series N[2,9]	18,000,000
Preference Shares, Series P[2,10]	16,000,000
Common Shares - issued and outstanding (voting equity shares)	799,855,473
Stock Options - issued and outstanding (20,161,711 vested)	37,524,181

1 Outstanding share data information is provided as at October 29, 2012.

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

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

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

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

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

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

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

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

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

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

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

September 30, 2012

Explanation of Responses:

CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(unaudited; millions of Canadian dollars, except per share amounts)				
Revenues				
Commodity sales	**4,648**	5,159	**13,990**	15,416
Gas distribution sales	**230**	230	**1,325**	1,338
Transportation and other services	**910**	888	**2,818**	2,990
	5,788	6,277	**18,133**	19,744
Expenses				
Commodity costs	**4,473**	4,959	**13,436**	14,835
Gas distribution costs	**79**	91	**779**	830
Operating and administrative	**724**	570	**2,037**	1,556
Depreciation and amortization	**293**	272	**883**	823
Environmental costs, net of recoveries	**(132)**	57	**(106)**	46
	5,437	5,949	**17,029**	18,090
	351	328	**1,104**	1,654
Income from equity investments	**32**	31	**104**	140
Other income/(expense)	**147**	(103)	**202**	8
Interest expense	**(200)**	(222)	**(630)**	(688)
	330	34	**780**	1,114
Income taxes recovery/(expense) *(Note 10)*	**(2)**	24	**(14)**	(223)
Earnings	**328**	58	**766**	891
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(108)**	(62)	**(233)**	(225)
Earnings/(loss) attributable to Enbridge Inc.	**220**	(4)	**533**	666
Preference share dividends	**(31)**	(1)	**(69)**	(5)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**189**	(5)	**464**	661
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.24**	(0.01)	**0.60**	0.88
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 6)*	**0.24**	(0.01)	**0.59**	0.87

See accompanying notes to the unaudited consolidated financial statements.

1

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(unaudited; millions of Canadian dollars)				
Earnings	**328**	58	**766**	891
Other comprehensive income/(loss)				
Change in unrealized loss on cash flow hedges, net of tax	**(96)**	(368)	**(224)**	(352)
Change in unrealized gain/(loss) on net investment hedges, net of tax	**46**	(102)	**28**	(62)
Other comprehensive income/(loss) from equity investees, net of tax	**4**	3	**3**	(2)
Reclassification to earnings of realized cash flow hedges, net of tax	**(2)**	(8)	**17**	(15)
Reclassification to earnings of unrealized cash flow hedges, net of tax	**3**	2	**2**	(6)
Reclassification to earnings of pension plan amortization amounts, net of tax	**7**	2	**14**	8
Change in foreign currency translation adjustment	**(297)**	524	**(262)**	305
Other comprehensive income/(loss)	**(335)**	53	**(422)**	(124)
Comprehensive income/(loss)	**(7)**	111	**344**	767
Compehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**19**	(190)	**(108)**	(247)
Comprehensive income/(loss) attributable to Enbridge Inc.	**12**	(79)	**236**	520
Preference share dividends	**(31)**	(1)	**(69)**	(5)
Comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(19)**	(80)	**167**	515

See accompanying notes to the unaudited consolidated financial statements.

2

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Nine months ended September 30, 2012	2011
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 6)*		
Balance at beginning of period	**1,056**	125
Preference shares issued	**2,260**	488
Balance at end of period	**3,316**	613
Common shares *(Note 6)*		
Balance at beginning of period	**3,969**	3,683
Common shares issued	**388**	-
Dividend reinvestment and share purchase plan	**213**	182
Shares issued on exercise of stock options	**39**	36
Balance at end of period	**4,609**	3,901
Additional paid-in capital		
Balance at beginning of period	**242**	131
Stock-based compensation	**21**	15
Options exercised	**(9)**	(5)
Issuance of treasury stock *(Note 8)*	**236**	-
Dilution gains and other	**7**	42
Balance at end of period	**497**	183
Retained earnings		
Balance at beginning of period	**3,926**	3,993
Earnings attributable to Enbridge Inc.	**533**	666
Preference share dividends	**(69)**	(5)
Common share dividends declared	**(668)**	(569)
Dividends paid to reciprocal shareholder	**14**	19
Redemption value adjustment attributable to redeemable noncontrolling interests	**(124)**	(22)
Balance at end of period	**3,612**	4,082
Accumulated other comprehensive loss *(Note 7)*		
Balance at beginning of period	**(1,532)**	(1,027)
Other comprehensive loss attributable to Enbridge Inc. common shareholders	**(297)**	(146)
Balance at end of period	**(1,829)**	(1,173)
Reciprocal shareholding		
Balance at beginning of period	**(187)**	(154)
Issuance of treasury stock *(Note 8)*	**61**	-
Acquisition of equity investment	**-**	(33)
Balance at end of period	**(126)**	(187)
Total Enbridge Inc. shareholders equity	**10,079**	7,419
Noncontrolling interests		
Balance at beginning of period	**3,141**	2,424
Earnings attributable to noncontrolling interests	**238**	228
Other comprehensive income/(loss) attributable to noncontrolling interests		
Change in realized and unrealized loss on cash flow hedges, net of tax	**(23)**	(98)
Change in foreign currency translation adjustment	**(101)**	120
	(124)	22
Comprehensive income attributable to noncontrolling interests	**114**	250
Contributions	**377**	482
Distributions	**(305)**	(272)
Dilution gains	**6**	18
Acquisitions	**(25)**	(27)
Other	**(5)**	2
Balance at end of period	**3,303**	2,877
Total equity	**13,382**	10,296
Dividends paid per common share	**0.8475**	0.7350

See accompanying notes to the unaudited consolidated financial statements.

3

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(unaudited; millions of Canadian dollars)				
Operating activities				
Earnings	**328**	58	**766**	891
Depreciation and amortization	**293**	272	**883**	823
Unrealized loss on derivative instruments, net	**217**	303	**748**	258
Cash distributions in excess of equity earnings	**31**	42	**435**	98
Deferred income taxes (recovery)/expense	**25**	46	**(59)**	197
Other	**(5)**	(10)	**42**	8
Change in regulatory assets and liabilities	**10**	1	**32**	25
Change in environmental liabilities, net of recoveries	**(37)**	10	**(46)**	(103)
Change in operating assets and liabilities	**(122)**	(33)	**(429)**	351
	740	689	**2,372**	2,548
Investing activities				
Additions to property, plant and equipment	**(1,477)**	(1,029)	**(3,536)**	(2,160)
Additions to intangible assets	**(46)**	(20)	**(130)**	(39)
Change in construction payable	**87**	225	**201**	107
Long-term investments	**(186)**	(104)	**(331)**	(294)
Affiliate loans, net	**1**	7	**4**	10
Acquisitions *(Note 4)*	**-**	-	**(221)**	(28)
Change in restricted cash	**2**	4	**(9)**	1
	(1,619)	(917)	**(4,022)**	(2,403)
Financing activities				
Net change in bank indebtedness and short-term borrowings	**391**	204	**285**	200
Net change in commercial paper and credit facility draws	**225**	(1,409)	**(692)**	(1,046)
Debenture and term note issues	**499**	1,229	**999**	1,229
Debenture and term note repayments	**(156)**	(1)	**(156)**	(151)
Net change in Southern Lights project financing	**6**	(10)	**(13)**	(50)
Contributions from noncontrolling interests	**438**	496	**441**	582
Distributions to noncontrolling interests	**(100)**	(102)	**(305)**	(272)
Distributions to redeemable noncontrolling interests	**(12)**	(8)	**(35)**	(22)
Preference shares issued	**827**	488	**2,245**	488
Common shares issued	**10**	7	**419**	29
Preference share dividends	**(29)**	(1)	**(63)**	(5)
Common share dividends	**(150)**	(127)	**(455)**	(387)
	1,949	766	**2,670**	595
Effect of translation of foreign denominated cash and cash equivalents	**(11)**	49	**(17)**	40
Increase in cash and cash equivalents	**1,059**	587	**1,003**	780
Cash and cash equivalents at beginning of period	**667**	569	**723**	376
Cash and cash equivalents at end of period	**1,726**	1,156	**1,726**	1,156

See accompanying notes to the unaudited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(unaudited; millions of Canadian dollars; number of shares in millions)	**September 30, 2012**	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents	**1,726**	723
Restricted cash	**26**	17
Accounts receivable and other	**3,640**	4,011
Accounts receivable from affiliates	**19**	55
Inventory	**877**	823
	6,288	5,629
Property, plant and equipment, net	**31,339**	28,941
Long-term investments	**3,272**	3,160
Deferred amounts and other assets	**2,846**	2,667
Intangible assets, net	**825**	711
Goodwill	**430**	440
Deferred income taxes	**8**	29
	45,008	41,577
Liabilities and equity		
Current liabilities		
Bank indebtedness	**362**	102
Short-term borrowings	**573**	548
Accounts payable and other	**4,628**	4,764
Accounts payable to affiliates	**-**	48
Interest payable	**221**	185
Environmental liabilities	**105**	175
Current maturities of long-term debt	**748**	354
	6,637	6,176
Long-term debt	**18,778**	19,251
Other long-term liabilities	**2,963**	2,323
Deferred income taxes	**2,500**	2,572
	30,878	30,322
Commitments and contingencies *(Note 12)*		
Redeemable noncontrolling interests	**748**	640
Equity		
Share capital		
Preference shares *(Note 6)*	**3,316**	1,056
Common shares (800 and 781 outstanding at September 30, 2012 and December 31, 2011, respectively) *(Note 6)*	**4,609**	3,969
Additional paid-in capital	**497**	242
Retained earnings	**3,612**	3,926
Accumulated other comprehensive loss *(Note 7)*	**(1,829)**	(1,532)
Reciprocal shareholding *(Note 8)*	**(126)**	(187)
Total Enbridge Inc. shareholders equity	**10,079**	7,474
Noncontrolling interests	**3,303**	3,141
	13,382	10,615
	45,008	41,577

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with United States generally accepted accounting principles (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company s consolidated financial statements and notes thereto for the year ended December 31, 2011 prepared in accordance with U.S. GAAP and filed with Canadian and United States securities regulators on a voluntary basis (U.S. GAAP Consolidated Financial Statements). In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly the Company s financial position as at September 30, 2012 and results of operations and cash flows for the three and nine month periods ended September 30, 2012 and 2011. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company s U.S. GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011, except as described in Note 2, Changes in accounting policies. Amounts are stated in Canadian dollars unless otherwise noted.

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

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

2. CHANGES IN ACCOUNTING POLICIES

FAIR VALUE MEASUREMENT

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

STATEMENT OF COMPREHENSIVE INCOME

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

GOODWILL IMPAIRMENT

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

3. SEGMENTED INFORMATION

Three months ended September 30, 2012	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**748**	**312**	**3,185**	**1,543**	**-**	**5,788**
Commodity and gas distribution costs	**-**	**(79)**	**(3,485)**	**(988)**	**-**	**(4,552)**
Operating and administrative	**(262)**	**(133)**	**(39)**	**(276)**	**(14)**	**(724)**
Depreciation and amortization	**(87)**	**(82)**	**(17)**	**(104)**	**(3)**	**(293)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**132**	**-**	**132**
	399	**18**	**(356)**	**307**	**(17)**	**351**
Income/(loss) from equity investments	**19**	**-**	**28**	**13**	**(28)**	**32**
Other income/(expense)	**8**	**(3)**	**7**	**13**	**122**	**147**
Interest income/(expense)	**(65)**	**(41)**	**(11)**	**(97)**	**14**	**(200)**
Income taxes recovery/(expense)	**(80)**	**8**	**131**	**(49)**	**(12)**	**(2)**
Earnings/(loss)	**281**	**(18)**	**(201)**	**187**	**79**	**328**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**-**	**(107)**	**-**	**(108)**
Preference share dividends	**-**	**-**	**-**	**-**	**(31)**	**(31)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**280**	**(18)**	**(201)**	**80**	**48**	**189**
Additions to property, plant and equipment1	**475**	**111**	**215**	**647**	**30**	**1,478**

Three months ended September 30, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	309	327	3,316	2,325	-	6,277
Commodity and gas distribution costs	-	(92)	(3,220)	(1,738)	-	(5,050)
Operating and administrative	(179)	(121)	(36)	(231)	(3)	(570)
Depreciation and amortization	(82)	(81)	(21)	(86)	(2)	(272)
Environmental costs, net of recoveries	-	-	-	(57)	-	(57)
	48	33	39	213	(5)	328
Income/(loss) from equity investments	1	-	34	13	(17)	31
Other income/(expense)	(46)	(1)	10	17	(83)	(103)
Interest expense	(63)	(40)	(13)	(84)	(22)	(222)
Income taxes recovery/(expense)	30	4	(24)	(37)	51	24
Earnings/(loss)	(30)	(4)	46	122	(76)	58
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	(61)	-	(62)
Preference share dividends	-	-	-	-	(1)	(1)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	(31)	(4)	46	61	(77)	(5)
Additions to property, plant and equipment1	308	141	127	448	5	1,029

Nine months ended September 30, 2012	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	**1,871**	**1,658**	**9,713**	**4,891**	**-**	**18,133**
Commodity and gas distribution costs	**-**	**(779)**	**(10,347)**	**(3,089)**	**-**	**(14,215)**
Operating and administrative	**(714)**	**(389)**	**(113)**	**(795)**	**(26)**	**(2,037)**
Depreciation and amortization	**(258)**	**(249)**	**(50)**	**(317)**	**(9)**	**(883)**
Environmental costs, net of recoveries	**-**	**-**	**-**	**106**	**-**	**106**
	899	**241**	**(797)**	**796**	**(35)**	**1,104**
Income/(loss) from equity investments	**26**	**-**	**82**	**40**	**(44)**	**104**
Other income/(expense)	**25**	**(4)**	**29**	**36**	**116**	**202**
Interest income/(expense)	**(193)**	**(122)**	**(33)**	**(291)**	**9**	**(630)**
Income taxes recovery/(expense)	**(164)**	**(35)**	**294**	**(141)**	**32**	**(14)**
Earnings/(loss)	**593**	**80**	**(425)**	**440**	**78**	**766**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(3)**	**-**	**(1)**	**(229)**	**-**	**(233)**
Preference share dividends	**-**	**-**	**-**	**-**	**(69)**	**(69)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**590**	**80**	**(426)**	**211**	**9**	**464**
Additions to property, plant and equipment1	**1,286**	**301**	**551**	**1,321**	**78**	**3,537**

Nine months ended September 30, 2011	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate	Consolidated
(millions of Canadian dollars)						
Revenues	1,283	1,745	9,907	6,809	-	19,744
Commodity and gas distribution costs	-	(831)	(9,612)	(5,222)	-	(15,665)
Operating and administrative	(494)	(357)	(97)	(595)	(13)	(1,556)
Depreciation and amortization	(240)	(239)	(60)	(277)	(7)	(823)
Environmental costs, net of recoveries	-	-	-	(46)	-	(46)
	549	318	138	669	(20)	1,654
Income/(loss) from equity investments	3	-	99	43	(5)	140
Other income/(expense)	25	(9)	30	54	(92)	8
Interest expense	(192)	(125)	(43)	(250)	(78)	(688)
Income taxes recovery/(expense)	(81)	(46)	(74)	(114)	92	(223)
Earnings/(loss)	304	138	150	402	(103)	891
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(2)	-	(1)	(222)	-	(225)
Preference share dividends	-	-	-	-	(5)	(5)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	302	138	149	180	(108)	661
Additions to property, plant and equipment1	671	306	310	863	12	2,162

1 Includes allowance for equity funds used during construction.

TOTAL ASSETS

	September 30, 2012	December 31, 2011
(millions of Canadian dollars)		
Liquids Pipelines	**15,280**	12,470
Gas Distribution	**7,076**	7,189
Gas Pipelines, Processing and Energy Services	**5,308**	4,468
Sponsored Investments	**13,816**	13,453
Corporate	**3,528**	3,997

45,008	41,577

8

Explanation of Responses:

4. ACQUISITIONS

GREENWICH WIND ENERGY PROJECT

On May 31, 2012, Enbridge acquired the remaining 10% interest in the Greenwich Wind Energy Project (Greenwich) through Greenwich Windfarm, LP for cash consideration of $27 million, increasing its ownership interest to 100%. The Company s interest in Greenwich continues to be held within the Gas Pipelines, Processing and Energy Services segment and is consolidated with the Company s results both before and after the acquisition.

SILVER STATE NORTH SOLAR PROJECT

On March 22, 2012, Enbridge acquired a 100% interest in the Silver State North Solar Project (Silver State), a solar farm located in Nevada, USA for $195 million (US$190 million). Cash consideration of $7 million (US$7 million) was paid during the first quarter of 2012 and the balance, net of a $1 million (US$1 million) holdback payable, was paid during the second quarter of 2012.

Silver State expands the Company s renewable energy business. Revenues of $4 million and $7 million were recognized in the three and nine months ended September 30, 2012, respectively. No revenues or earnings were recognized in any prior period as the solar project commenced operations in the second quarter of 2012. Silver State is included within the Gas Pipelines, Processing and Energy Services segment.

March 22,	**2012**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Accounts receivable and other[1]	**54**
Property, plant and equipment	**141**
	195
Purchase price:	
Cash	**195**

1 *The Company acquired the right to apply for a $54 million (US$55 million) United States Treasury grant under a program which reimburses eligible applicants for a portion of costs related to installing specified renewable energy property. The grant, which was applied for subsequent to commercial operations, was received in October 2012.*

5. CREDIT FACILITIES

September 30, 2012	Maturity Dates[1]	Total Facilities	Credit Facility Draws[2]	Available
(millions of Canadian dollars)				
Liquids Pipelines	2014	**300**	**25**	**275**
Gas Distribution	2014	**712**	**580**	**132**

Sponsored Investments	2014-2017	**3,131**	**1,072**	**2,059**
Corporate	2013-2017	**7,429**	**1,681**	**5,748**
		11,572	**3,358**	**8,214**
Southern Lights project financing[3]	2014	**1,480**	**1,417**	**63**
Total credit facilities		**13,052**	**4,775**	**8,277**

1 *Total facilities include $35 million in demand facilities with no maturity date.*
2 *Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.*
3 *Total facilities inclusive of $59 million for debt service reserve letters of credit.*

Credit facilities carry a weighted average standby fee of 0.18% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2013 to 2017.

Commercial paper and credit facility draws, net of short-term borrowings, of $2,520 million (2011 - $3,359 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

6. SHARE CAPITAL

COMMON SHARES

	September 30, 2012		December 31, 2011	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Balance at beginning of period	**781**	**3,969**	770	3,683
Dividend reinvestment and share purchase plan	**6**	**213**	7	229
Shares issued on exercise of stock options	**3**	**39**	4	57
Common Shares issued[1]	**10**	**388**	-	-
Balance at end of period	**800**	**4,609**	781	3,969

1 Gross proceeds - $400 million; net issuance costs - $12 million.

PREFERENCE SHARES

	September 30, 2012		December 31, 2011	
	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of shares in millions)				
Preference Shares, Series A	**5**	**125**	5	125
Preference Shares, Series B	**20**	**490**	20	490
Preference Shares, Series D	**18**	**441**	18	441
Preference Shares, Series F[1]	**20**	**490**	-	-
Preference Shares, Series H[2]	**14**	**342**	-	-
Preference Shares, Series J[3]	**8**	**194**	-	-
Preference Shares, Series L[4]	**16**	**402**	-	-
Preference Shares, Series N[5]	**18**	**441**	-	-
Preference Shares, Series P[6]	**16**	**391**	-	-
Balance at end of period		**3,316**		1,056

1 Gross proceeds - $500 million; net issuance costs - $10 million.
2 Gross proceeds - $350 million; net issuance costs - $8 million.
3 Gross proceeds - US$200 million; net issuance costs - US$4 million.

4 Gross proceeds - US$400 million; net issuance costs - US$9 million.
5 Gross proceeds - $450 million; net issuance costs - $9 million.
6 Gross proceeds - $400 million; net issuance costs - $9 million.

Characteristics of the Preference Shares are as follows:

	Initial Yield	Dividend1	Per Share Base Redemption Value2	Redemption and Conversion Option Date2,3	Right to Convert Into3,4
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.5%	$1.375	$25	-	-
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N5	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P6	4.0%	$1.000	$25	March 1, 2019	Series Q

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

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

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

4 Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.40% (Series C), 2.37% (Series E), 2.51% (Series G), 2.12% (Series I), 2.65% (Series O) or 2.50% (Series Q)); or US$25 x (number of days in quarter/365) x (90-day United States Government treasury bill rate + 3.05% (Series K) or 3.15% (Series M)).

5 A cash dividend of $0.3753 per share will be paid on December 1, 2012 to Series N shareholders. The regular quarterly dividend of $0.25 per share will begin in the first quarter of 2013.

6 A cash dividend of $0.2164 per share will be paid on December 1, 2012 to Series P shareholders. The regular quarterly dividend of $0.25 per share will begin in the first quarter of 2013.

EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company s pro-rata weighted average interest in its own common shares of 18 million and 21 million for the three and nine months ended September 30, 2012 (2011 - 27 million and 24 million), resulting from the Company s reciprocal investment in Noverco Inc. (Noverco).

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

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(number of shares in millions)				
Weighted average shares outstanding	**780**	750	**769**	751
Effect of dilutive options	**12**	11	**12**	9
Diluted weighted average shares outstanding	**792**	761	**781**	760

For both the three and nine months ended September 30, 2012, nil and 3,542,500 anti-dilutive stock options (2011 - 48,000 for both the three and nine months ended September 30) with a weighted average exercise price of $nil and $39.34, respectively (2011 - $32.02 for both the three and nine months ended September 30) were excluded from the diluted earnings per share calculation.

11

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

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Equity Investees	Pension Plan Amortization Amounts	Cumulative Translation Adjustment	Total
Balance at January 1, 2011	(66)	480	(11)	(142)	(1,288)	(1,027)
Changes during the period	(377)	(72)	(3)	8	185	(259)
Tax impact	102	10	1	-	-	113
	(275)	(62)	(2)	8	185	(146)
Balance at September 30, 2011	(341)	418	(13)	(134)	(1,103)	(1,173)
Balance at January 1, 2012	**(476)**	**461**	**(28)**	**(286)**	**(1,203)**	**(1,532)**
Changes during the period	**(242)**	**32**	**8**	**19**	**(161)**	**(344)**
Tax impact	**61**	**(4)**	**(5)**	**(5)**	**-**	**47**
	(181)	**28**	**3**	**14**	**(161)**	**(297)**
Balance at September 30, 2012	**(657)**	**489**	**(25)**	**(272)**	**(1,364)**	**(1,829)**

8. RECIPROCAL SHAREHOLDING

At December 31, 2011, Noverco owned an approximate 8.9% reciprocal shareholding in the Common Shares of the Company. On March 22, 2012, Noverco sold 22.5 million Enbridge Common Shares through a secondary offering, thereby reducing the Company s reciprocal shareholding to 6.0%. Both the Company s equity investment in Noverco, included in Long-term investments, and Equity have increased by $297 million, net of tax, as a result of this transaction. During the second quarter of 2012, the Company received a cash dividend of approximately $317 million from Noverco.

9. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK

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

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

Foreign Exchange Risk

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

12

Interest Rate Risk

The Company s earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2017 at an average swap rate of 2.18%.

The Company s earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2016. A total of $11,147 million of future fixed rate term debt issuances have been hedged at an average swap rate of 3.35%.

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

Commodity Price Risk

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

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

Equity Price Risk

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

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the balance sheet location and carrying value of the Company s derivative instruments. The Company did not have any outstanding fair value hedges at September 30, 2012 or December 31, 2011.

September 30, 2012	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments	Effects of Netting	Total Net Derivative Instruments1
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**4**	**16**	**212**	**232**	**-**	**232**
Interest rate contracts	**1**	**-**	**10**	**11**	**(3)**	**8**
Commodity contracts	**18**	**-**	**170**	**188**	**(17)**	**171**
Other contracts	**1**	**-**	**10**	**11**	**-**	**11**
	24	**16**	**402**	**442**	**(20)**	**422**
Deferred amounts and other assets						
Foreign exchange contracts	**14**	**92**	**334**	**440**	**-**	**440**
Interest rate contracts	**9**	**-**	**14**	**23**	**(1)**	**22**
Commodity contracts	**9**	**-**	**93**	**102**	**(6)**	**96**
Other contracts	**2**	**-**	**3**	**5**	**-**	**5**
	34	**92**	**444**	**570**	**(7)**	**563**
Accounts payable and other						
Foreign exchange contracts	**(5)**	**-**	**(92)**	**(97)**	**-**	**(97)**
Interest rate contracts	**(561)**	**-**	**(3)**	**(564)**	**3**	**(561)**
Commodity contracts	**(11)**	**-**	**(388)**	**(399)**	**17**	**(382)**
	(577)	**-**	**(483)**	**(1,060)**	**20**	**(1,040)**
Other long-term liabilities						
Foreign exchange contracts	**(51)**	**(3)**	**(21)**	**(75)**	**-**	**(75)**
Interest rate contracts	**(513)**	**-**	**(16)**	**(529)**	**1**	**(528)**
Commodity contracts	**(7)**	**-**	**(588)**	**(595)**	**6**	**(589)**
Other contracts	**(1)**	**-**	**-**	**(1)**	**-**	**(1)**
	(572)	**(3)**	**(625)**	**(1,200)**	**7**	**(1,193)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**(38)**	**105**	**433**	**500**	**-**	**500**
Interest rate contracts	**(1,064)**	**-**	**5**	**(1,059)**	**-**	**(1,059)**
Commodity contracts	**9**	**-**	**(713)**	**(704)**	**-**	**(704)**
Other contracts	**2**	**-**	**13**	**15**	**-**	**15**
	(1,091)	**105**	**(262)**	**(1,248)**	**-**	**(1,248)**

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

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

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

September 30, 2012	2012	2013	2014	2015	2016	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**474**	**55**	**468**	**25**	**25**	**420**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**572**	**1,968**	**2,402**	**2,751**	**2,333**	**2,715**
Euro dollar forwards - sell *(millions of Euros)*	**1**	**-**	**-**	**-**	**-**	**-**
Euro dollar forwards - purchase *(millions of Euros)*	**5**	**4**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**818**	**3,621**	**3,582**	**3,449**	**3,169**	**3,047**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**1,750**	**3,440**	**3,055**	**1,760**	**1,142**	**-**
Equity contracts *(millions of Canadian dollars)*	**37**	**35**	**33**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**8**	**45**	**23**	**19**	**1**	**-**

Commodity contracts - crude oil *(millions of barrels)*	**8**	**37**	**37**	**29**	**23**	**27**
Commodity contracts - NGL *(millions of barrels)*	**1**	**2**	**1**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**35**	**38**	**40**	**48**	**63**	**58**

15

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

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(28)**	57	**(19)**	15
Interest rate contracts	**(1)**	(560)	**(190)**	(545)
Commodity contracts	**(27)**	101	**54**	106
Other contracts	**(3)**	1	**(3)**	3
Net investment hedges				
Foreign exchange contracts	**34**	(88)	**16**	(63)
	(25)	(489)	**(142)**	(484)
Amount of gain/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*				
Cash flow hedges				
Foreign exchange contracts1	**2**	1	**1**	1
Interest rate contracts2	**(7)**	4	**17**	13
Commodity contracts3	**-**	(13)	**(3)**	(43)
Other contracts	**-**	-	**-**	(1)
	(5)	(8)	**15**	(30)
Amount of gain/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Cash flow hedges				
Interest rate contracts2	**(1)**	3	**3**	(6)
Commodity contracts3	**4**	(1)	**(1)**	-
	3	2	**2**	(6)

1 *Reported within Transportation and other services revenue and Other income in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*

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

16

The Company estimates that $110 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on foreign exchange rates, interest rates and commodity prices in effect when derivative contracts currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 63 months at September 30, 2012.

Non-Qualifying Derivatives

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

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Foreign exchange contracts1	**303**	(234)	242	(232)
Interest rate contracts2	**(1)**	1	(2)	5
Commodity contracts3	**(531)**	(56)	(973)	(3)
Other contracts4	**(2)**	9	3	9
Total unrealized derivative fair value loss	**(231)**	(280)	(730)	(221)

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments *(Note 12)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company s primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all of the terms and conditions of its committed credit facilities at September 30, 2012. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility a counterparty will default on its contractual obligations. The Company enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into International Securities Dealers Association (ISDA) agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company s credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

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

(millions of Canadian dollars)	**September 30, 2012**	December 31, 2011
Canadian financial institutions	**377**	431
United States financial institutions	**192**	287
European financial institutions	**299**	257
Other[1]	**116**	112
	984	1,087

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

As at September 30, 2012, the Company had provided letters of credit totaling $264 million in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. The Company holds no cash collateral on asset exposures at September 30, 2012 or December 31, 2011.

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

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

FAIR VALUE MEASUREMENTS

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

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

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company s Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations. The Company does not have any other financial instruments categorized as Level 1.

Level 2

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

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

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs include long-dated derivative power contracts and NGL and natural gas contracts. The Company does not have any other financial instruments categorized in Level 3.

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

Fair Value of Derivatives

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

September 30, 2012	Level 1	Level 2	Level 3	Total Gross Derivative Instruments	Effects of Netting	Total
(millions of Canadian dollars)						
Financial assets						
Current derivative assets						
Foreign exchange contracts	-	232	-	232	-	232
Interest rate contracts	-	11	-	11	(3)	8
Commodity contracts	3	79	106	188	(17)	171
Other contracts	-	11	-	11	-	11
	3	333	106	442	(20)	422
Long-term derivative assets						
Foreign exchange contracts	-	440	-	440	-	440
Interest rate contracts	-	23	-	23	(1)	22
Commodity contracts	-	55	47	102	(6)	96
Other contracts	-	5	-	5	-	5
	-	523	47	570	(7)	563
Financial liabilities						
Current derivative liabilities						
Foreign exchange contracts	-	(97)	-	(97)	-	(97)
Interest rate contracts	-	(564)	-	(564)	3	(561)
Commodity contracts	-	(323)	(76)	(399)	17	(382)
	-	(984)	(76)	(1,060)	20	(1,040)
Long-term derivative liabilities						
Foreign exchange contracts	-	(75)	-	(75)	-	(75)
Interest rate contracts	-	(529)	-	(529)	1	(528)
Commodity contracts	-	(494)	(101)	(595)	6	(589)
Other contracts	-	(1)	-	(1)	-	(1)
	-	(1,099)	(101)	(1,200)	7	(1,193)
Total net financial asset/(liability)						
Foreign exchange contracts	-	500	-	500	-	500
Interest rate contracts	-	(1,059)	-	(1,059)	-	(1,059)
Commodity contracts	3	(683)	(24)	(704)	-	(704)
Other contracts	-	15	-	15	-	15
	3	(1,227)	(24)	(1,248)	-	(1,248)

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

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

	Fair value at September 30, 2012 *(millions of Canadian dollars)*	**Unobservable Input**	**Minimum Price**	**Maximum Price**	**Weighted Average Price**	
Commodity Contracts - Financial1						
Natural Gas	5	Forward Gas Price	2.72	4.44	3.40	$/mmbtu3
NGL	23	Forward NGL Price	0.19	2.05	0.95	$/gallon
Power	(57)	Forward Power Price	49.75	64.14	55.54	$/MWH
Commodity Contracts - Physical1						
Natural Gas	(7)	Forward Gas Price	2.26	8.73	4.57	$/mmbtu3
Crude	1	Forward Crude Price	72.30	115.03	88.97	$/barrel
Power	(1)	Forward Power Price	27.17	36.37	32.67	$/MWH
Commodity Options2						
Natural Gas	1	Option Volatility	26%	36%	31%	
NGL	11	Option Volatility	40%	110%	72%	

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

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

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

	Nine months ended, September 30,	
	2012	2011
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**32**	(24)
Total gains/(loss), unrealized		
Included in earnings1	**(52)**	35
Included in OCI	**3**	(25)
Settlements	**(7)**	46
Level 3 net derivative asset/(liability) at end of period	**(24)**	32

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

The Company s policy is to recognize transfers between levels as at the last day of the reporting period. There were no transfers as at September 30, 2012 or 2011.

Fair Value of Other Financial Instruments

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. At September 30, 2012 and December 31, 2011, all equity investments of this nature held by the Company are recognized at cost with a carrying value of $64 million at September 30, 2012 (December 31, 2011 - $56 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $242 million at September 30, 2012 (December 31, 2011 - $285 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.34% to 4.40%. At September 30, 2012, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2011 - $580 million).

At September 30, 2012, the Company s long-term debt had a carrying value of $19,526 million (December 31, 2011 - $19,605 million) and a fair value of $22,474 million (December 31, 2011 - $22,620 million).

10. INCOME TAXES

Significant variances between the effective income tax rate and the weighted average Canadian statutory income tax rate were as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
Canadian weighted average statutory tax rate	**25.7%**	27.1%	**25.7%**	27.1%
Foreign rate differential[1]	**(10.3%)**	35.1%	**(11.9%)**	1.7%
Other	**(14.8%)**	(132.8%)	**(12.0%)**	(8.8%)
	0.6%	(70.6%)	**1.8%**	20.0%

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

11. RETIREMENT AND POSTRETIREMENT BENEFITS

The Company has three registered pension plans which provide either defined benefit or defined contribution pension benefits, or both, to employees of the Company. The Liquids Pipelines and Gas Distribution pension plans (collectively, the Canadian Plans) provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge United States pension plan (the United States Plan) provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans which provide pension benefits in excess of the basic plans for certain employees. The Company also provides other postretirement benefits (OPEB), which primarily include supplemental health and dental, health spending account and life insurance coverage, for qualifying retired employees.

NET BENEFIT COSTS RECOGNIZED

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
(millions of Canadian dollars)				
Benefits earned during the period	**23**	17	**71**	50
Interest cost on projected benefit obligations	**20**	22	**61**	64
Expected return on plan assets	**(23)**	(23)	**(71)**	(70)
Amortization of prior service costs	**1**	-	**1**	1
Amortization of actuarial loss	**5**	7	**17**	19
Net benefit costs[1]	**26**	23	**79**	64

1 *Included in net benefit costs for the three and nine months ended September 30, 2012 are costs related to OPEB of $4 million and $13 million, respectively (2011 - $4 million and $11 million).*

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Nine months ended September 30,	**2012**	2011	**2012**	2011
(millions of Canadian dollars)				
Contributions paid	**70**	44	**8**	3
Contributions expected to be paid in the next three months	**39**		**3**	
Total contributions expected to be paid in the year	**109**		**11**	

12. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials, as well as transportation, totaling $3,334 million which are expected to be paid within the next five years.

EEP LAKEHEAD SYSTEM CRUDE OIL RELEASES

Enbridge holds an approximate 22% combined direct and indirect ownership interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Lakehead System Line 14 Crude Oil Release

On July 27, 2012, a release of crude oil was detected on Line 14 of EEP s Lakehead System near Grand Marsh, Wisconsin. The estimated volume of oil released was approximately 1,200 barrels. EEP received a Corrective Action Order (CAO) from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on July 30, 2012, followed by an amended CAO on August 1, 2012. The

CAOs required EEP to take certain corrective actions, some of which have already been completed and some are still ongoing, as part of an overall plan for its Lakehead System. A notable part of the CAOs was to hire an independent third party pipeline expert to review and assess EEP s overall integrity program. An independent third party expert was contracted during the third quarter of 2012 and their work is currently ongoing.

Upon restart of Line 14 on August 7, 2012, PHMSA restricted the operating pressure to 80% of the pressure in place at the time immediately prior to the incident. The pressure restrictions will remain in place until such time EEP can demonstrate that the root cause of the incident has been remediated.

EEP has updated the disclosed estimate for repair and remediation related costs associated with this crude oil release to approximately US$12 million ($2 million after-tax attributable to Enbridge), inclusive of approximately US$2 million of lost revenue, and excluding any fines and penalties. Despite the efforts EEP has made to ensure the reasonableness of its estimate, changes to the estimated amounts associated with this release are possible as more reliable information becomes available. EEP will be pursuing claims under Enbridge s comprehensive insurance policy, although it does not expect any recoveries to be significant.

Lakehead System Line 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

During the second quarter of 2012, local authorities allowed the Kalamazoo River and Morrow Lake, which were affected by the Line 6B crude oil release, to be re-opened for recreational use. EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. EEP expects to make payments for additional costs associated with submerged oil and sheen monitoring and recovery operations, including remediation and restoration of the area, containment management, air and groundwater monitoring, scientific studies and hydrodynamic modeling, along with legal, professional and regulatory costs through future periods. All of the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

On July 2, 2012, EEP received a Notice of Probable Violation (NOPV) from the PHMSA related to the July 26, 2010 Line 6B crude oil release, which resulted in payment of a US$3.7 million civil penalty in the third quarter of 2012. EEP included the amount of the penalty in its total estimated cost for the Line 6B crude oil release. In addition, on July 10, 2012 the National Transportation Safety Board presented the results of its investigation into the Line 6B crude oil release and subsequently publicly posted its final report on July 26, 2012.

As at September 30, 2012, EEP had revised the total incident cost accrual to US$810 million ($136 million after-tax attributable to Enbridge), primarily due to an estimate of extended oversight by regulators and additional legal costs associated with various lawsuits, which is an increase of US$25 million ($5 million after-tax attributable to Enbridge) from its estimate at June 30, 2012. This total estimate is before insurance recoveries and excludes additional fines and penalties, which may be imposed by federal, state and local government agencies, other than the PHMSA civil penalty described above. On October 3, 2012, EEP received a letter from the Environmental Protection Agency (EPA) regarding a Proposed Order for potential incremental containment and active recovery of submerged oil. EEP is in discussions with the EPA regarding the agency s intent with respect to certain elements of the Proposed Order and the appropriate scope of these activities. As such, EEP has not included significant additional costs related to this Proposed Order in its total incident cost accrual and it is impracticable to provide an estimate at this time.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at September 30, 2012. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

EEP continues to monitor the areas affected by the crude oil release from Line 6A of its Lakehead System near Romeoville, Illinois in September 2010 for any additional requirements; however, the cleanup, remediation and restoration of the areas affected by the release have been substantially completed.

In connection with this crude oil release, the cost estimate remains at approximately US$48 million ($7 million after-tax attributable to Enbridge), before insurance recoveries and excluding fines and penalties. EEP has the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. EEP is pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates which renews in May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents such as those incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by Enbridge s comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability. Based on EEP s remediation spending through September 30, 2012, Enbridge and its affiliates have exceeded the limits of their coverage under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy.

EEP recognized US$170 million ($24 million after-tax attributable to Enbridge) of insurance recoveries as reductions to Environmental costs, net of recoveries, for the Line 6B crude oil release in the Consolidated Statements of Earnings for the three and nine months ended September 30, 2012, compared with US$85 million ($13 million after-tax attributable to Enbridge) and US$135 million ($21 million after-tax attributable to Enbridge) for the three and nine months ended September 30, 2011, respectively. As at September 30, 2012, EEP had recorded total insurance recoveries of US$505 million ($74 million after-tax attributable to Enbridge) for the Line 6B crude oil release. EEP expects to record receivables for additional amounts claimed for recovery pursuant to insurance policies during the period it deems realization of the claim for recovery to be probable.

Effective May 1, 2012, Enbridge renewed its comprehensive insurance program, through April 30, 2013, with a current liability aggregate limit of US$660 million, including sudden and accidental pollution liability.

Legal and Regulatory Proceedings

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

TAX MATTERS

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

OTHER LEGAL AND REGULATORY PROCEEDINGS

The Company and its subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, Management believes that the resolution of such actions and proceedings will not have a material impact on the Company s consolidated financial position or results of operations.