ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2015

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This Management's Discussion and Analysis (MD&A) dated May 12, 2016 should be read in conjunction with the audited amended consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2015, prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and filed on May 12, 2016. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

Effective January 1, 2016, Enbridge revised its reportable segments to better reflect the underlying operations of the Company. The Company believes this new format more clearly describes the financial performance of its business segments, provides increased transparency with respect to operational results and aligns with business segment decision making and management.

The Company is filing this MD&A to retrospectively apply the revisions to its reportable segments to the annual MD&A of the Company that was previously filed on February 19, 2016. Revisions to the segmented information presentation include:

- The replacement of the previous segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments; and Corporate with new segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services;
- Presenting the Earnings before interest and income taxes (EBIT) of each segment as opposed to Earnings attributable to Enbridge Inc. common shareholders. Amounts related to Interest expense, Income taxes, Earnings attributable to noncontrolling interests and redeemable noncontrolling interests and Preference share dividends are now reported on a consolidated basis.

These changes had no impact on reported consolidated earnings.

OVERVIEW

Enbridge, a Canadian Company, is a North American leader in delivering energy. As a transporter of energy, Enbridge operates, in Canada and the United States, the world's longest crude oil and liquids transportation system. The Company also has significant and growing involvement in natural gas gathering, transmission and midstream businesses. As a distributor of energy, Enbridge owns and operates Canada's largest natural gas distribution company and provides distribution services in Ontario, Quebec, New Brunswick and New York State. As a generator of energy, Enbridge has interests in nearly 2,800 megawatts (MW) (2,000 MW net) of renewable and alternative energy generating capacity which is operating, secured or under construction, and the Company continues to expand its interests in wind, solar and geothermal power. Enbridge employs nearly 11,000 people, primarily in Canada and the United States.

The Company's activities are carried out through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Lakehead Pipeline System (Lakehead System), Regional Oil Sands System, Mid-Continent and Gulf Coast, Southern Lights Pipeline, Bakken System and Feeder Pipelines and Other.

GAS DISTRIBUTION
Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD), which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick and the Company's investment in Noverco Inc. (Noverco).

GAS PIPELINES AND PROCESSING
Gas Pipelines and Processing consists of investments in natural gas pipelines and gathering and processing facilities. Investments in natural gas pipelines include the Company's interests in the Alliance Pipeline, the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas extraction and fractionation business located near the terminus of the Alliance Pipeline, Canadian Midstream assets located in northeast British Columbia and northwest Alberta and United States Midstream assets located primarily in Texas and Oklahoma.

GREEN POWER AND TRANSMISSION
Green Power and Transmission consists of the Company's investments in renewable energy assets and transmission facilities. Renewable energy assets consist of wind, solar, geothermal and waste heat recovery facilities and are located in Canada primarily in the provinces of Alberta, Ontario and Quebec and in the United States primarily in Colorado, Texas and Indiana.

ENERGY SERVICES
The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company's volume commitments on Alliance Pipeline, Vector and other pipeline systems.

ELIMINATIONS AND OTHER
In addition, Eliminations and Other includes operating and administrative costs and foreign exchange costs which are not allocated to business segments. Also included in Eliminations and Other are new business development activities, general corporate investments and elimination of transactions between segments required to present financial performance and financial position on a consolidated basis.

CANADIAN RESTRUCTURING PLAN

On September 1, 2015, Enbridge announced it had completed the transfer of its Canadian Liquids Pipelines business, held through Enbridge Pipelines Inc. (EPI) and Enbridge Pipelines (Athabasca) Inc. (EPAI), and certain Canadian renewable energy assets to the Fund Group (comprising Enbridge Income Fund (the Fund), Enbridge Commercial Trust (ECT), Enbridge Income Partners LP (EIPLP) and the subsidiaries of EIPLP) for aggregate consideration of $30.4 billion plus incentive distribution and performance rights (the Canadian Restructuring Plan or the Transaction).

The Transaction is a key component of Enbridge's Financial Optimization Strategy introduced in December 2014, which included an increase in the Company's targeted dividend payout. It advances the Company's sponsored vehicle strategy and supports Enbridge's 33% dividend increase effective March 1, 2015 and a further 14% dividend increase effective March 1, 2016. The Transaction is expected to provide Enbridge with an alternate source of funding for its enterprise wide growth initiatives and enhance its competitiveness for new organic growth opportunities and asset acquisitions.

In conjunction with the execution of the Transaction, Enbridge adopted a supplemental cash flow metric, available cash flow from operations (ACFFO), which was introduced in the second quarter of 2015 and is now a part of the Company's normal course annual and quarterly reporting of financial performance and in the provision of guidance. ACFFO is used to assess the performance of the Company's base business and the impact of its growth program. The Company also started expressing its dividend payout range as a percentage of ACFFO rather than adjusted earnings and has established a long-term target payout of 40% to 50% of ACFFO.

CONSIDERATION

Upon closing of the Transaction, Enbridge received $18.7 billion of units in the Fund Group, comprised of approximately $3 billion of ordinary units of the Fund and $15.7 billion of common equity units of EIPLP, which at the time of the Transaction was an indirect subsidiary of the Fund. The Fund Group also assumed debt of EPI and EPAI of approximately $11.7 billion. In addition, a portion of the consideration to be received by Enbridge over time will be in the form of units which carry Temporary Performance Distribution Rights (TPDR). The TPDR are designed to allow Enbridge to capture increasing value from the secured growth embedded within the transferred businesses; however, the cash flows derived from this incentive mechanism will be deferred (until such time as the units become convertible to a class of cash paying units in the fourth year after issuance).

Enbridge will continue to earn a base incentive fee from the Fund Group through management and incentive fees and Incentive Distribution Rights (IDR), which entitle it to receive 25% of the pre-incentive distributable cash flow above a base distribution threshold of $1.295 per unit, adjusted for a tax factor. The base incentive fee is paid out of ECT. Distributions over $1.890 per unit will be paid out of EIPLP. In addition, Enbridge received the TPDR, a distribution equivalent to 33% of pre-incentive distributable cash flow above the base distribution of $1.295 per unit. The TPDR are paid in the form of Class D units of EIPLP and will be issued each month until the later of the end of 2020 or 12 months after the Canadian portion of the Line 3 Replacement Program (Canadian L3R Program) enters service. The Class D unitholders receive a distribution each month equal to the per unit amount paid on Class C units of EIPLP, but to be paid in kind in additional Class D units. Each Class D unit is convertible into a cash paying Class C unit of EIPLP in the fourth year after its issuance.

The ordinary trust units of the Fund (Fund Units), Class A units of EIPLP and the EIPLP Class C units will pay a per unit cash distribution equivalent to the per unit cash distribution that the Fund pays on its units held by Enbridge Income Fund Holdings Inc. (ENF). The Fund Units, EIPLP’s Class C units and existing preferred units of ECT also include an exchange right whereby they may be converted into common shares of ENF on a one-for-one basis.

FINANCING PLAN

To acquire an increasing ownership interest in the Fund Group, ENF’s financing plan contemplates the issuance by ENF of $600 million to $800 million of public equity per year in one or more tranches through 2018 to fund an increasing investment in the Canadian Liquids Pipelines business. Enbridge has agreed to backstop the equity funding required by ENF to undertake the growth program embedded in the assets it acquired in the Transaction. The amount of public equity issued by ENF will be adjusted as necessary to match its capacity to raise equity funding on favourable terms. On November 6, 2015, ENF successfully completed an equity offering of 21.5 million common shares at a price of $32.60 per share for gross proceeds of $700 million. Concurrent with the closing of the equity offering, Enbridge subscribed for 5.3 million common shares at a price of $32.60 per share, for total proceeds of $174 million, on a private placement basis to maintain its 19.9% ownership interest in ENF.

On April 20, 2016, ENF completed a public equity offering of 20.4 million common shares at a price of $28.25 per common share (the Offering Price) for gross proceeds of $575 million. Concurrent with the closing of the equity offering, Enbridge subscribed for 5.1 million common shares at a price of $28.25 per share, for total proceeds of $143 million, on a private placement basis to maintain its 19.9% ownership interest in ENF. ENF used the proceeds from the sale of the common shares to subscribe for additional Fund Units at the Offering Price. The proceeds from the issuance of the Fund Units are being used to repay short-term indebtedness pending investment in the secured growth capital programs of EPAI and EPI.

DEVELOPMENT OPPORTUNITIES

The Canadian Liquids Pipelines business is expected to have future organic growth opportunities beyond the current inventory of secured projects. The Fund Group has a first right to execute any such projects that fall within the footprint of the Canadian Liquids Pipelines business. Should the Fund Group choose not to proceed with a specific growth opportunity, Enbridge may pursue such opportunity.

ECONOMIC INTEREST

Upon closing of the Transaction, Enbridge's overall economic interest in the Fund Group, including all of its direct and indirect interests in the Fund Group, was 91.9%. Upon completion of the $700 million common share issuance in November 2015 and $575 million common share issuance in April 2016 discussed above, Enbridge’s economic interest, through its ownership of ENF, decreased to 89.2% and 86.9%, respectively. As ENF executes on its financing plan and increases its ownership in the Fund Group over time, Enbridge's economic interest is expected to decline to approximately 80% by the end of 2018.

FUND GOVERNANCE

Enbridge continues to act as the manager of the Fund Group and operator and commercial developer of the Canadian Liquids Pipelines business. This will ensure continuity of management and operational expertise, with an ongoing commitment to the safe and reliable operation of the system. As a result of its significant ownership interest, Enbridge has the right to appoint a majority of the Trustees of the Board of ECT for as long as the Company holds a majority economic interest in the Fund Group. A standing conflicts committee has been established to review certain material transactions and arrangements where the interests of Enbridge, or its affiliates, and the relevant entity in the Fund Group, or its affiliates, come into conflict.

UNITED STATES SPONSORED VEHICLE STRATEGY

On May 2, 2016, Enbridge Energy Partners, L.P. (EEP) announced that it is evaluating opportunities to strengthen its business in light of the current commodity price environment which is particularly impacting the performance of its natural gas gathering and processing assets. As part of this evaluation, EEP is exploring strategic alternatives for its investments in Midcoast Operating Partners, L.P. and Midcoast Energy Partners, L.P. (MEP). These various strategic alternatives may include, but are not necessarily limited to: asset sales; mergers, joint ventures, reorganizations or recapitalizations; and further reductions in operating and capital expenditures. The evaluation process is in its initial stage and is ongoing, and no decision on any particular strategic alternative has been reached by EEP.

Enbridge has a large inventory of United States liquid pipeline assets which would be well suited to EEP, and Enbridge has previously indicated that it would from time to time consider drop down opportunities to EEP of these assets. However, in light of current market conditions, and their effect on EEP’s financing capacity, it is unlikely that any such drop down transactions will be pursued in the near term.

THE FUND GROUP 2014 DROP DOWN TRANSACTION

In November 2014, the Fund Group completed the acquisition of Enbridge’s 50% interest in the United States portion of the Alliance Pipeline (Alliance Pipeline US) and the subscription for and purchase of Class A units of certain Enbridge subsidiaries that indirectly own the Canadian and United States segments of Southern Lights Pipeline (Southern Lights Class A units). The Southern Lights Class A units, which are non-voting and do not confer any governance or ownership rights in Southern Lights Pipeline, will provide a defined cash flow stream to the Fund Group. Total consideration for the transaction was approximately $1.8 billion. Enbridge received on closing approximately $421 million in cash and $461 million in the form of preferred units of ECT, an entity within the Fund Group. Under the agreement, Enbridge provided bridge debt financing (Bridge Financing) to the Fund Group in the form of an $878 million long-term note payable by the Fund Group and bearing interest of 5.5% per annum. In November 2014, the Fund Group issued $1,080 million of medium-term notes with a portion of these proceeds used to fully repay the Bridge Financing to Enbridge. The Fund Group also issued $421 million of trust units to

ENF to fund the cash component of the consideration. Enbridge applied approximately $84 million of cash to acquire additional common shares of ENF, thereby maintaining its 19.9% interest in ENF. Enbridge's overall economic interest in the Fund Group was reduced from 67.3% to 66.4% upon completion of the transaction. At the time of the transaction, the Fund Group previously owned a 50% investment in the Canadian portion of the Alliance Pipeline (Alliance Pipeline Canada).

The asset transfers described above occurred between entities under common control of Enbridge, and the intercompany gains realized by the selling entities in the year ended December 31, 2014 have been eliminated from the Consolidated Financial Statements of Enbridge. However, as these transactions involved the sale of shares and partnership units, all tax consequences have remained in consolidated earnings and resulted in a charge of $157 million in 2014.

Through this transaction, which essentially resulted in a partial monetization of the assets by Enbridge through sale to noncontrolling interests (being ENF's public shareholders), Enbridge realized a source of funds of $323 million for the year ended December 31, 2014, as presented within Financing Activities on the Consolidated Statements of Cash Flows.

PERFORMANCE OVERVIEW

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
(millions of Canadian dollars, except per share amounts)				
Earnings attributable to common shareholders				
Liquids Pipelines	**675**	467	**1,806**	1,980
Gas Distribution	**111**	107	**455**	432
Gas Pipelines and Processing	**69**	243	**(229)**	467
Green Power and Transmission	**50**	41	**177**	149
Energy Services	**92**	234	**325**	730
Eliminations and Other	**(156)**	(214)	**(899)**	(456)
Earnings before interest and income taxes[1]	**841**	878	**1,635**	3,302
Interest expense	**(371)**	(313)	**(1,624)**	(1,129)
Income taxes	**(94)**	(249)	**(170)**	(611)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**76**	(157)	**410**	(203)
Preference share dividends	**(74)**	(71)	**(288)**	(251)
Earnings/(loss) attributable to common shareholders	**378**	88	**(37)**	1,108
Discontinued operations - Gas Pipelines and Processing	**-**	-	**-**	46
	378	88	**(37)**	1,154
Earnings/(loss) per common share	**0.44**	0.11	**(0.04)**	1.39
Diluted earnings/(loss) per common share	**0.44**	0.10	**(0.04)**	1.37
Adjusted earnings				
Liquids Pipelines	**949**	700	**3,384**	2,592
Gas Distribution	**128**	107	**446**	391
Gas Pipelines and Processing	**88**	74	**336**	293
Green Power and Transmission	**49**	39	**175**	151
Energy Services	**(22)**	9	**61**	42
Eliminations and Other	**(74)**	(37)	**(246)**	(60)
Adjusted earnings before interest and income taxes[1]	**1,118**	892	**4,156**	3,409
Interest expense[2]	**(372)**	(261)	**(1,273)**	(926)
Income taxes[2]	**(130)**	(101)	**(486)**	(434)
Noncontrolling interests and redeemable noncontrolling interests[2]	**(48)**	(50)	**(243)**	(225)
Discontinued operations	**-**	-	**-**	1
Preference share dividends	**(74)**	(71)	**(288)**	(251)
Adjusted earnings[1]	**494**	409	**1,866**	1,574
Adjusted earnings per common share[1]	**0.58**	0.49	**2.20**	1.90
Cash flow data				
Cash provided by operating activities	**806**	656	**4,571**	2,547
Cash used in investing activities	**(2,296)**	(3,737)	**(7,933)**	(11,891)
Cash provided by financing activities	**1,457**	3,221	**2,973**	9,770
Available cash flow from operations[3]				
Available cash flow from operations	**876**	610	**3,154**	2,506
Dividends				
Common share dividends declared	**401**	297	**1,596**	1,177
Dividends paid per common share	**0.465**	0.350	**1.86**	1.40
Revenues				
Commodity sales	**6,074**	6,192	**23,842**	28,281
Gas distribution sales	**672**	835	**3,096**	2,853
Transportation and other services	**2,168**	1,770	**6,856**	6,507
	8,914	8,797	**33,794**	37,641
Total assets	**84,515**	72,741	**84,515**	72,741
Total long-term liabilities	**51,362**	42,190	**51,362**	42,190

1 *Adjusted earnings before interest and income taxes (adjusted EBIT), adjusted earnings and adjusted earnings per common share are non-GAAP measures that do not have any standardized meaning prescribed by generally accepted accounting principles. For more information on non-GAAP measures see page 13.*
2 *These balances are presented net of adjusting items.*
3 *ACFFO is defined as cash flow provided by operating activities before changes in operating assets and liabilities (including changes in regulatory assets and liabilities and environmental liabilities) less distributions to noncontrolling interests and redeemable noncontrolling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, non-recurring or non-operating factors. ACFFO is a non-GAAP measure that does not have any standardized meaning prescribed by GAAP – see Non-GAAP Measures.*

EBIT AND EARNINGS/(LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS

EBIT

For the year ended December 31, 2015, EBIT was $1,635 million compared to $3,302 million for the year ended December 31, 2014. As discussed below in *Performance Overview – Adjusted Earnings*, the Company has continued to deliver strong earnings growth from operations over the course of the last two years. However, the positive impact of this growth and the comparability of the Company's earnings are impacted by a number of unusual, non-recurring or non-operating factors that are enumerated in *Non-GAAP Reconciliations* and discussed in the results for each reporting segment, the most significant of which are changes in unrealized derivative fair value gains and losses. For the years ended December 31, 2015 and December 31, 2014, the Company's EBIT reflected $1,679 million and $36 million of unrealized derivative fair value loss, respectively. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks which create volatility in short-term earnings. Over the long term, Enbridge believes its hedging program supports the reliable cash flows and dividend growth upon which the Company's investor value proposition is based.

In addition, 2015 EBIT reflects a goodwill impairment charge of $440 million ($167 million after-tax attributable to Enbridge) recognized in the second quarter of 2015 related to EEP's natural gas and NGL businesses. The prolonged decline in commodity prices has reduced producers' expected drilling programs and negatively impacted volumes on EEP's natural gas and NGL pipelines and processing systems, which EEP holds directly and indirectly through its partially-owned subsidiary, MEP.

Earnings/(Loss) Attributable to Common Shareholders

Loss attributable to common shareholders was $37 million ($0.04 loss per common share) for the year ended December 31, 2015 compared with earnings of $1,154 million ($1.39 earnings per common share) for the year ended December 31, 2014. In addition to the factors discussed above, the comparability of the Company's year-over-year operating results was impacted by the transfer of assets between entities under common control of Enbridge in connection with the Canadian Restructuring Plan which resulted in $351 million of one-time charges, mainly related to the de-designation of interest rate hedges and a write-off of a regulatory asset in respect of taxes.

Loss for 2015 and earnings for 2014 were also negatively impacted by taxes recognized on the transfer of assets between entities under common control of Enbridge. Intercompany gains realized as a result of these transfers for both years have been eliminated for accounting purposes. However, as these transactions involved the sale of partnership units, all tax consequences have remained in consolidated earnings and resulted in charges of $39 million and $157 million in 2015 and 2014, respectively.

Fourth quarter EBIT and earnings performance drivers were largely consistent with year-to-date trends and both continued to be impacted by changes in unrealized derivative fair value and foreign exchange gains and losses. Aside from the operating factors discussed in *Performance Overview – Adjusted Earnings*, factors unique to the fourth quarter of 2015 included the impact of employee severance costs in relation to the Company's enterprise-wide reduction of workforce, which resulted in a net charge of $25 million to earnings.

ADJUSTED EBIT

The Company's investor value proposition is built upon visible growth, a reliable business model and a growing income and cash flow stream, supported by a rigorous focus on safe and reliable operations and a disciplined approach to investment and project execution. This growth is a reflection of the underlying strength of Enbridge's existing asset portfolio combined with the continuing execution of its large growth capital program, which resulted in a number of new assets placed into service over this period. The Company's current five year plan includes approximately $26 billion of commercially secured growth projects of which approximately $8 billion were brought into service in 2015. The remaining $18 billion are expected to be completed and placed into service between 2016 and 2019.

For the year ended December 31, 2015, adjusted EBIT was $4,156 million, an increase of $747 million over the comparable period of 2014. Growth in consolidated adjusted EBIT was largely driven by stronger contributions from the Liquids Pipelines segment. The Canadian Mainline contribution increased primarily from higher throughput that resulted from strong oil sands production in western Canada combined with strong downstream refinery demand, as well as ongoing efforts by the Company to optimize capacity utilization and to enhance scheduling efficiency with shippers. These positive factors were partially offset by a lower year-over-year average Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll. The Lakehead System also experienced year-over-year growth in adjusted EBIT, mainly due to higher throughput and tolls, as well as contributions from new assets placed into service in 2014 and 2015, the most prominent being the expansion of the Company's mainline system completed in July 2015 and the replacement and expansion of Line 6B completed in 2014. In 2015, the Company also benefitted from a full-year of EBIT contributions from Mid-Continent and Gulf Coast, mainly attributed to the Flanagan South and Seaway Twin pipelines, both of which commenced service in late 2014.

The Company's adjusted EBIT within certain of its United States operating businesses also increased as a result of the strength of the United States dollar compared with the Canadian dollar. The offsetting impact of components of the Company's foreign exchange risk mitigation strategy is disclosed and discussed in *Eliminations and Other*.

ADJUSTED EARNINGS

For the year ended December 31, 2015, adjusted earnings increased $292 million to $1,866 million compared with $1,574 million for the same period of 2014. The Company has consistently delivered on its investor value proposition, growing adjusted earnings from $1.90 per common share in 2014 to $2.20 per common share in 2015.

Partially offsetting the adjusted EBIT growth discussed above was adjusted higher interest expense resulting from the incurrence of incremental debt to fund asset growth and the impact of refinancing construction debt with longer-term debt financing. Preference share dividends were also higher resulting from additional preference shares issued in 2014 to fund the Company's growth capital program. For a detailed discussion on the Company's financing activities refer to *Liquidity and Capital Resources*.

Also partially offsetting the adjusted EBIT growth was adjusted income taxes expense which increased over the previous year as a result of higher adjusted earnings. This was partially offset by increased tax benefits associated with certain financing activities as well as a higher benefit from the effect of rate-regulated accounting for deferred income taxes.

The year-over-year increase in adjusted EBIT was also partially offset by higher adjusted earnings attributable to the redeemable noncontrolling interests in the Fund Group. Despite the increase in the Company's economic interest in the Fund Group as a result of the Canadian Restructuring Plan, the adjusted earnings attributable to the Fund Group's redeemable noncontrolling interests increased period-over-period as a result of the positive effects of the Canadian Restructuring Plan and the Fund Group 2014 Drop Down Transaction on the Fund Group's adjusted earnings. For further details, refer to *Canadian Restructuring Plan* and *The Fund Group 2014 Drop Down Transaction*.

Interest expense, income taxes and noncontrolling interests and redeemable noncontrolling interests for each period were impacted by adjustments for unusual, non-recurring and non-operating factors.

With respect to the fourth quarter of 2015, many of the annual trends discussed above were also the factors in driving adjusted EBIT and adjusted earnings growth over the fourth quarter of 2014.

AVAILABLE CASH FLOW FROM OPERATIONS

ACFFO was $876 million for the three months ended December 31, 2015 compared with $610 million for the three months ended December 31, 2014. ACFFO was $3,154 million for the year ended December 31, 2015 compared with $2,506 million for the year ended December 31, 2014. The Company experienced strong quarter-over-quarter and year-over-year growth in ACFFO which was driven by the same factors as discussed in *Adjusted EBIT* above.

Contributing to the period-over-period increase in ACFFO were lower maintenance capital expenditures in 2015 compared with the corresponding 2014 periods. Over the last few years, the Company has made a significant investment in the ongoing support, maintenance and integrity management of its pipelines and other infrastructure and in the preservation of the service capability of its existing assets. The period-over-period decrease in maintenance capital expenditures is due to the completion of specific maintenance programs in 2014. The Company plans to continue to invest in its maintenance capital program to support the safety and reliability of its operations.

Also contributing to the period-over-period increase in ACFFO were cash distributions received from the Company's equity investments, which were higher than the equity earnings from such investments. During the year ended December 31, 2015, the Company received cash distributions of $719 million compared with $564 million received during the year ended December 31, 2014. Cash distributions received in the fourth quarter of 2015 were $180 million compared with $174 million received in the fourth quarter of 2014.

The period-over-period increase discussed above was partially offset by higher interest expense and higher preference share dividends as discussed under *Adjusted Earnings* above.

The period-over-period increase in ACFFO was also partially offset by higher current income taxes expense primarily attributable to the Company's ability to carry back tax losses in the 2014 taxation year to recover prior year taxes paid. The ability to carry back and recover prior year taxes in the 2015 taxation year was significantly reduced.

Also partially offsetting the period-over-period increase in ACFFO were increased distributions to noncontrolling interests in EEP and to redeemable noncontrolling interests in the Fund. Distributions were higher in 2015 compared with the distributions in 2014 mainly as a result of increased public ownership and distributions per unit in EEP and the Fund.

IMPACT OF THE RECENT DECLINE IN COMMODITY PRICES

Enbridge's value proposition is built on the foundation of its reliable business model. The majority of its earnings and cash flow are generated from tolls and fees charged for the energy delivery services that it provides to its customers. Business arrangements are structured to minimize exposure to commodity price movements and any residual exposure is closely monitored and managed through disciplined hedging programs. Commercial structures are typically designed to provide a measure of protection against the risk of a scenario where falling commodity prices indirectly impact the utilization of the Company's facilities. Protection against volume risk is generally achieved through regulated cost of service tolling arrangements, long-term take-or-pay contract structures and fee for service arrangements with specific features to mitigate exposure to falling throughput.

Smaller components of Enbridge's earnings are more exposed to the impacts of commodity price volatility. This includes Energy Services, where opportunities to benefit from location, time and quality differentials can be affected by commodity market conditions. They also include the Company's interest in Aux Sable's natural gas extraction and fractionation facilities and natural gas gathering and processing businesses held through EEP; however, the impact on Enbridge's overall financial performance is relatively small and any inherent commodity price risk is mitigated by hedging programs, commercial arrangements and Enbridge's partial ownership interest.

In the third quarter of 2014, the price of crude oil began a dramatic decline. Benchmark prices for crude, which had been trading over US$105 per barrel in June 2014, fell to as low as US$37 per barrel by the end of 2015 as a result of significant increases in production both inside and outside of North America. Prices have declined further since the beginning of 2016, falling to below US$30 per barrel in January and are expected to remain volatile in the near to mid-term as the market seeks to re-balance supply and demand. The current commodity price environment has had an impact on shippers on Enbridge's pipelines who have responded to price declines by reducing investment in exploration and development programs throughout 2015 and into 2016. Although Enbridge is exposed to throughput risk under the Competitive Toll Settlement (CTS) on the Canadian Mainline and under certain tolling agreements applicable to other liquids pipelines assets, including Lakehead System, the reduction in investment by the Company's shippers is not expected to materially impact the financial performance of the Company. It is expected that existing conventional and oil sands production should be more than sufficient to support continued high utilization of the Company's mainline system. Entering 2016, nominations for service on the pipelines have continued to exceed available capacity on the system, resulting in apportionment of nominated volumes. Due to the nature of the commercial structures described above, Enbridge's earnings and cash flow are not expected to be materially affected by the current low price environment.

The decline in oil prices is also causing some sponsors of oil sands development programs to reconsider the timing of previously announced upstream development projects. Cancellation or deferral of these projects would affect longer-term supply growth from the Western Canadian Sedimentary Basin (WCSB). Enbridge's existing growth capital program described under *Growth Projects – Commercially Secured Projects* has been commercially secured and is expected to generate reliable and predictable earnings growth through 2019 and beyond. Importantly, after taking into account the potential for some of these projects to be cancelled or deferred in an environment where low prices persist, Enbridge's most recent near-term supply forecast reaffirms that the expansions and extensions of its liquids pipeline system completed in 2015 and currently in progress will provide cost-effective transportation services to key markets in North America and will be well utilized.

Similar to the crude oil price trend, prices for NGL have decreased sharply as they are, to varying extents, correlated to crude oil. As well, in some cases NGL components have also been experiencing regional supply imbalances that have exacerbated an already challenging environment. Natural gas prices had already been relatively low for some time as production growth continued to outpace demand growth, but the pace of the price decline hastened in 2015 with continuing production levels resulting in rising inventories in storage which reached an all-time record high in November 2015.

In the current low-price environment, Enbridge is working closely with producers to find ways to optimize capacity and provide enhanced access to markets in order to alleviate locational pricing discounts. Examples include the recently completed expansion of the Company's liquids mainline system which resulted in the partial alleviation of upstream apportionment experienced in the first half of 2015 and completion of the Company's reversal and capacity expansion of Line 9B as well as the completion of the Southern Access Extension Project (Southern Access Extension) in the fourth quarter of 2015, which have provided access to the Eastern Canada and Patoka markets, respectively.

CASH FLOWS

Cash provided by operating activities was $4,571 million for the year ended December 31, 2015, mainly driven by strong operating performance from the Company's core assets, particularly from Liquids Pipelines and the cash flow generated from growth projects placed into service in recent years. Partially offsetting these cash inflows were changes in operating assets and liabilities as further discussed in *Liquidity and Capital Resources*.

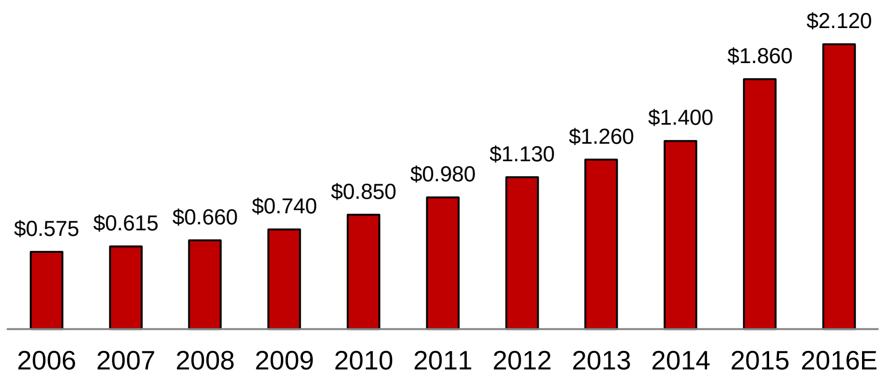
In the first eight months of 2015, during the design and negotiation of the Canadian Restructuring Plan, the Company did not access the public capital markets as regularly as it had in previous years. However, following the closing of the Canadian Restructuring Plan, Enbridge again began to access the public debt and equity markets in normal course. In 2015, Enbridge through its sponsored vehicles issued equity of approximately $1.1 billion. In addition, Enbridge and its subsidiaries issued approximately $1.6 billion in medium-term notes, US$1.6 billion in senior notes and expanded and extended the average maturity of its secured credit facilities. The proceeds of the capital market transactions, together with additional borrowings from its credit facilities, cash generated from operations and cash on hand were more than sufficient to finance the Company's approximately $8 billion of projects that were placed into service in 2015 and are expected to provide financing flexibility for the Company's growth capital program in 2016. As discussed in *Liquidity and Capital Resources*, the Company continues to utilize its sponsored vehicles to enhance its enterprise-wide funding program.

Furthermore, in March 2016, Enbridge issued equity of approximately $2.3 billion. The proceeds from this issuance are being used to reduce short-term indebtedness and are expected to be sufficient to fulfill equity funding requirements for Enbridge's current commercially secured growth program through the end of 2017. In addition, Enbridge through its sponsored vehicles issued equity of approximately $0.6 billion in April 2016, proceeds of which will continue to provide financing flexibility for the Company's growth capital program in 2016.

DIVIDENDS

The Company has paid common share dividends in every year since it became a publicly traded company in 1953. In December 2015, the Company announced a 14% increase in its quarterly dividend to $0.530 per common share, or $2.120 annualized, effective March 1, 2016.

Dividends per Common Share



As described under the *Canadian Restructuring Plan*, Enbridge's target dividend payout policy range is 40% to 50% of ACFFO. In 2015, the dividend payout was 50.0% (2014 - 46.4%) of ACFFO. For the 10-year period ended December 2015, the Company's compound annual average dividend growth rate was 13.9%.

REVENUES

The Company generates revenues from three primary sources: commodity sales, gas distribution sales and transportation and other services. Commodity sales of $23,842 million for the year ended December 31, 2015 (2014 - $28,281 million) were generated primarily through the Company's energy services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas and NGL to generate a margin, which is typically a small fraction of gross revenue. While sales revenues generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year to year depending on market conditions and commodity prices.

Gas distribution sales revenues are primarily earned by EGD and are recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Transportation and other services revenues are earned from the Company's crude oil and natural gas pipeline transportation businesses and also include power production revenues from the Company's portfolio of renewable and power generation assets. For the Company's transportation assets operating under market-based arrangements, revenues are driven by volumes transported and tolls. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator, and in most cost-of-service based arrangements are reflective of the Company's cost to provide the service plus a regulator-approved rate of return. Higher transportation and other services revenues reflected increased throughput on the Company's core liquids pipeline assets combined with the incremental revenues associated with assets placed into service over the past two years.

The Company's revenues also included changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The unrealized mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but the Company believes over the long term, the economic hedging program supports reliable cash flows and dividend growth.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide information about the Company and its subsidiaries and affiliates, including management's assessment of Enbridge 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'', "likely" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected EBIT or expected adjusted EBIT; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected ACFFO; expected future cash flows; expected costs related to projects under construction; expected in-service dates for projects under construction; expected capital expenditures; expected equity funding requirements for the Company's commercially secured growth program; estimated future dividends; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; expectations regarding the impact of the Canadian Restructuring Plan (or the Transaction); dividend payout policy and dividend payout expectation; and strategic alternatives currently being evaluated in connection with the United States sponsored vehicles strategy.

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 following: the expected supply of and demand for crude oil, natural gas, NGL and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labour and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; weather; the impact of the Transaction and dividend policy on the Company's future cash flows; credit ratings; capital project funding; expected EBIT or expected adjusted EBIT; expected earnings/(loss) or adjusted earnings/(loss); expected earnings/(loss) or adjusted earnings/(loss) per share; expected future cash flows and expected future ACFFO; and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Company's services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Company operates and may impact levels of demand for the Company's services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected EBIT, adjusted EBIT, earnings/(loss), adjusted earnings/(loss) and associated per share amounts, ACFFO, the impact of the Transaction on Enbridge or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated completion dates and expected capital expenditures, include the following: 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; the impact of weather and customer and regulatory approvals on construction and in-service schedules.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to the impact of the Transaction, operating performance, regulatory parameters, dividend policy, project approval and support, weather, economic and competitive conditions, public opinion, changes in tax law and tax rate increases, exchange rates, interest rates, commodity prices and supply of 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 applicable 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 EBIT, adjusted earnings/(loss) and ACFFO. Adjusted EBIT represents EBIT adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. Adjusted earnings/(loss) represent earnings or loss attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors included in adjusted EBIT, as well as adjustments for unusual, non-recurring or non-operating factors in respect of interest expense, income taxes, noncontrolling interests and redeemable noncontrolling interests on a consolidated basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments.

ACFFO is defined as cash flow provided by operating activities before changes in operating assets and liabilities (including changes in regulatory assets and liabilities and environmental liabilities) less distributions to noncontrolling interests and redeemable noncontrolling interests, preference share dividends and maintenance capital expenditures, and further adjusted for unusual, non-recurring or non-operating factors.

Management believes the presentation of adjusted EBIT, adjusted earnings/(loss) and ACFFO provide useful information to investors and shareholders as they provide increased transparency and insight into the performance of the Company. Management uses adjusted EBIT and adjusted earnings/(loss) to set targets and to assess the performance of the Company. Management also uses ACFFO to assess the performance of the Company and to set its dividend payout target. Adjusted EBIT, adjusted EBIT for each segment, adjusted earnings/(loss) and ACFFO are not measures that have standardized meaning prescribed by U.S. GAAP and are not U.S. GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. The tables below summarize the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATIONS
EBIT to Adjusted Earnings

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
(millions of Canadian dollars)				
Earnings before interest and income taxes	**841**	878	**1,635**	3,302
Adjusting items[1]:				
Changes in unrealized derivative fair value loss[2]	**79**	6	**1,679**	36
Canadian Restructuring Plan	**-**	-	**357**	-
Goodwill impairment loss	**-**	-	**440**	-
Unrealized intercompany foreign exchange gains	**(21)**	(16)	**(131)**	(16)
Hydrostatic testing	**23**	-	**72**	-
Make-up rights adjustments	**50**	16	**42**	35
Leak remediation costs, net of leak insurance recoveries	**(21)**	(5)	**(26)**	92
Warmer/(colder) than normal weather	**22**	-	**(15)**	(48)
Gains on sale of non-core assets and investment, net of losses	**-**	(22)	**(88)**	(38)
Asset impairment losses	**88**	18	**108**	18
Employee severance costs	**41**	6	**41**	6
Project development and transaction costs	**2**	9	**25**	17
Other	**14**	2	**17**	5
Adjusted earnings before interest and income taxes	**1,118**	892	**4,156**	3,409
Interest expense	**(371)**	(313)	**(1,624)**	(1,129)
Income taxes	**(94)**	(249)	**(170)**	(611)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**76**	(157)	**410**	(203)
Discontinued operations	**-**	-	**-**	46
Preference share dividends	**(74)**	(71)	**(288)**	(251)
Adjusting items in respect of:				
Interest expense	**(1)**	52	**351**	203
Income taxes	**(36)**	148	**(316)**	177
Discontinued operations	**-**	-	**-**	(45)
Noncontrolling interests and redeemable noncontrolling interests	**(124)**	107	**(653)**	(22)
Adjusted earnings	**494**	409	**1,866**	1,574

1 The above table summarizes adjusting items by nature. For a detailed listing of adjusting items by segment, refer to individual segment discussions.

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

Adjusted EBIT to ACFFO

To facilitate understanding of the relationship between adjusted EBIT and ACFFO, the following table provides a reconciliation of these two key non-GAAP measures.

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**1,118**	892	**4,156**	3,409
Depreciation and amortization[1]	**541**	426	**2,024**	1,577
Maintenance capital[2]	**(200)**	(312)	**(720)**	(970)
	1,459	1,006	**5,460**	4,016
Interest expense[3]	**(372)**	(261)	**(1,273)**	(926)
Current income taxes[3]	**(53)**	5	**(160)**	(12)
Preference share dividends	**(74)**	(71)	**(288)**	(245)
Distributions to noncontrolling interests	**(179)**	(140)	**(680)**	(535)
Distributions to redeemable noncontrolling interests	**(34)**	(24)	**(114)**	(79)
Cash distributions in excess of equity earnings[3]	**64**	57	**244**	196
Other non-cash adjustments	**65**	38	**(35)**	91
Available cash flow from operations (ACFFO)	**876**	610	**3,154**	2,506
1 Depreciation and amortization:				
Liquids Pipelines	***336***	*252*	***1,227***	*911*
Gas Distribution	***78***	*78*	***308***	*304*
Gas Pipelines and Processing	***70***	*58*	***272***	*221*
Green Power and Transmission	***47***	*33*	***186***	*124*
Energy Services	***-***	*-*	***(1)***	*(2)*
Eliminations and Other	***10***	*5*	***32***	*19*
	541	*426*	***2,024***	*1,577*
2 Maintenance capital:				
Liquids Pipelines	***(44)***	*(155)*	***(278)***	*(500)*
Gas Distribution	***(118)***	*(102)*	***(302)***	*(296)*
Gas Pipelines and Processing	***(17)***	*(19)*	***(45)***	*(62)*
Green Power and Transmission	***-***	*-*	***-***	*(1)*
Eliminations and Other	***(21)***	*(36)*	***(95)***	*(111)*
	(200)	*(312)*	***(720)***	*(970)*

3 These balances are presented net of adjusting items.

Available Cash Flow from Operations

The following table provides a reconciliation of cash provided by operating activities (a GAAP measure) to ACFFO.

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
(millions of Canadian dollars)				
Cash provided by operating activities - continuing operations	**806**	656	**4,571**	2,528
Adjusted for changes in operating assets and liabilities[1]	**474**	470	**688**	1,777
	1,280	1,126	**5,259**	4,305
Distributions to noncontrolling interests	**(179)**	(140)	**(680)**	(535)
Distributions to redeemable noncontrolling interests	**(34)**	(24)	**(114)**	(79)
Preference share dividends	**(74)**	(71)	**(288)**	(245)
Maintenance capital expenditures[2]	**(200)**	(312)	**(720)**	(970)
Significant adjusting items:				
Weather normalization	**16**	(1)	**(11)**	(36)
Project development and transaction costs	**2**	15	**44**	19
Realized inventory revaluation allowance[3]	**(52)**	-	**(474)**	-
Hydrostatic testing	**23**	-	**72**	-
Employee severance costs	**30**	6	**30**	6
Other items	**64**	11	**36**	41
Available cash flow from operations (ACFFO)	**876**	610	**3,154**	2,506

1 *Changes in operating assets and liabilities include changes in regulatory assets and liabilities and environmental liabilities, net of recoveries.*

2 *Maintenance capital expenditures are expenditures that are required for the ongoing support and maintenance of the existing pipeline system or that are necessary to maintain the service capability of the existing assets (including the replacement of components that are worn, obsolete or completing their useful lives). For the purpose of ACFFO, maintenance capital excludes expenditures that extend asset useful lives, increase capacities from existing levels or reduce costs to enhance revenues or provide enhancements to the service capability of the existing assets.*

3 *Realized inventory revaluation allowance relates to losses on sale of previously written down inventory for which there is an approximate offsetting realized derivative gain in ACFFO.*

CORPORATE VISION AND STRATEGY

VISION

Enbridge's vision is to be the leading energy delivery company in North America. In pursuing this vision, the Company plays a critical role in enabling the economic well-being and quality of life of North Americans, who depend on access to plentiful energy. The Company transports, distributes and generates energy, and its primary purpose is to deliver the energy North Americans need in the safest, most reliable and most efficient way possible.

Among its peers, Enbridge strives to be the leader, which means not only leadership in value creation for shareholders but also leadership with respect to worker and public safety and environmental protection associated with its energy delivery infrastructure, as well as in customer service, community investment and employee satisfaction. Driven by this vision, the Company delivers value for shareholders from a proven and unique value proposition, which combines visible growth, a reliable business model and a dependable and growing income stream.

STRATEGY

The Company's initiatives centre around eight areas of strategic emphasis in four key focus areas. These strategies are reviewed at least annually with direction from the Company's Board of Directors.

COMMITMENT TO SAFETY AND OPERATIONAL RELIABILITY	
EXECUTE	**SECURE THE LONGER-TERM FUTURE**
Focus on project management *Preserve financing strength and flexibility*	*Strengthen core businesses* *Develop new platforms for growth and diversification*

MAINTAIN THE FOUNDATION
Uphold Enbridge values *Maintain the Company's social license to operate* *Attract, retain and develop highly capable people*

Commitment to Safety and Operational Reliability

Safety and operational reliability remains the Company's number one priority and sets the foundation for the strategic plan. The commitment to safety and operational reliability means achieving and maintaining industry leadership in safety (process, public and personal) and ensuring the reliability and integrity of the systems the Company operates in order to generate, transport and deliver the energy society counts on and to protect the environment.

Under the umbrella of the Company's Operational Risk Management Plan (ORM Plan) introduced in 2010, Enbridge has undertaken extensive maintenance, integrity and inspection programs across its pipeline systems. The ORM Plan has resulted in strong improvements in the area of safety and operational risk management, bolstering incident response capabilities, employee and public safety protocols and improved communications with landowners and first responders. In addition, an enterprise-wide safety and risk management framework has been implemented to ensure the Company identifies, prioritizes and effectively prevents and mitigates risks across the enterprise. The Company strives to embed a common risk management framework within its operations and those of its joint venture partners. Supporting these initiatives is a safety culture that strives towards a target of 100% safe operations, with a belief that all incidents can be prevented. To achieve the goal of industry leadership, the Company measures its performance as compared to standard industry performance, transparently reports its results and continues to use external assessments to measure its performance.

Execute

Focus on Project Management

Enbridge's objective is to safely deliver projects on time and on budget and at the lowest practical cost while maintaining the highest standards for safety, quality, customer satisfaction and environmental and regulatory compliance. With an approximate $26 billion portfolio of commercially secured growth projects, successful project execution is critical to achieving the Company's long-term growth plan. These projects are predominantly liquids focused, but increasingly include green energy, natural gas, offshore and gas distribution initiatives. Enbridge, through its Major Projects Group (Major Projects), continues to build upon and enhance the key elements of its rigorous project management processes including: employee and contractor safety; long-term supply chain agreements; quality design, materials and construction; extensive regulatory and public consultation; robust cost, schedule and risk controls; and efficient project transition to operating units.

Preserve Financing Strength and Flexibility

The maintenance of adequate financing strength and flexibility is crucial to Enbridge's growth strategy. Enbridge's financing strategies are designed to ensure the Company has sufficient financial flexibility to meet its capital requirements. To support this objective, the Company develops financing plans and strategies to manage credit ratings, diversify its funding sources and maintain substantial standby bank credit capacity and access to capital markets in both Canada and the United States. As part of the Company's risk management policy, the Company engages in a comprehensive long-term economic hedging program to mitigate the impact of fluctuations in interest rates, foreign exchange and commodity price on the Company's earnings. This economic hedging program together with ongoing management of credit exposures to customers, suppliers and counterparties supports one of the key tenets of the Company's investor value proposition, a reliable business model.

Enbridge has also actively used its sponsored vehicles, primarily through asset drop downs, to cost-effectively fund a portion of its large growth capital program. In 2015, the Company completed the Canadian Restructuring Plan, which transferred the majority of its Canadian Liquids Pipelines business and certain renewable energy assets to the Fund Group. See *Canadian Restructuring Plan*. For further discussion on the Company's financing strategies, refer to *Liquidity and Capital Resources*.

The Company continually assesses ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analysed and assessed using strict operating, strategic and financial criteria with the objective of ensuring the effective deployment of capital and the enduring financial strength and stability of the Company.

Secure the Longer-Term Future

Strengthen Core Businesses

Within the Company's crude oil transportation business, strategies to strengthen the core business are focused on optimizing asset performance, strengthening stakeholder and customer relationships and providing access to new markets for production from western Canada and the Bakken regions, all while ensuring safe and reliable operations. The Company's asset optimization efforts focus on maximizing the operational and financial performance of its infrastructure assets within established risk parameters, providing competitive services and value to customers. The Company's assets are strategically located and well-positioned to capitalize on opportunities. In 2015, Enbridge continued to execute on its Gulf Coast Access Program through the completion of a phase of the Mainline Expansion project that increased the capacity of the liquids mainline system by 230,000 barrels per day (bpd) and contributed to record throughput levels on the liquids mainline in December 2015. Significant milestones were also reached on the Company's Eastern Access Program, as the Company completed the reversal of Line 9B and placed the 300,000 bpd line into service in December 2015. The Eastern Access Program provides increased access to refineries in the upper midwest United States and eastern Canada. Under the Company's Light Oil Market Access Program, Enbridge completed the Line 9 capacity expansion portion of the Line 9B project noted above as well as Southern Access Extension, which was completed in December 2015 and provides additional crude oil capacity of 300,000 bpd from Flanagan, Illinois to Patoka, Illinois. Additionally, EEP further expanded the capacity of the Lakehead System between Superior, Wisconsin and Griffith, Indiana through the completion of a phase of the Southern Access expansion in May 2015 and the completion of the twinning of the Spearhead North pipeline (Spearhead North Twin) in November 2015.

While executing its record growth capital program in the recent years, the Company has also been undertaking an extensive integrity program across its liquids and gas systems. The Company's Line 3 Replacement Program (L3R Program) will support the safety and operational reliability of the overall system and enhance the flexibility on the mainline system allowing the Company to further optimize throughput. For further details on the L3R Program, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines.*

The strategic focus within Regional Oil Sands Systems is to optimize existing asset corridors and provide innovative, creative, competitive and customer oriented solutions to WCSB producers to secure the incremental supply of crude oil expected from the western Canadian oil sands projects over the next decade. Within this regional focus area, Enbridge has approximately $5 billion of regional infrastructure growth projects currently under development which are expected to enter service from 2015 to 2017. Approximately $1 billion worth of projects were completed in 2015. Approximately $4 billion are expected to be completed and placed into service in 2016 and 2017. In the Bakken region, Enbridge and EEP's growth is focused on the development and construction of the US$2.6 billion Sandpiper Project (Sandpiper). Upon completion, now expected for early 2019, Sandpiper will provide North Dakota producers enhanced access to premium light crude oil markets. For recent developments on this matter, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Sandpiper Project (EEP).*

In addition to executing its secured growth program, the Company is focused on extending growth beyond 2019 through continued expansion of liquids pipelines, as well as development of its natural gas and power businesses. The Company's natural gas strategies include leveraging the competitive advantages of its existing assets, expanding its footprint into emerging supply areas and establishing more direct linkage to growing markets. Combined, Alliance Pipeline and the Aux Sable NGL extraction and fractionation plant are well-positioned to provide liquids-rich gas transportation and processing to developing regions in northeast British Columbia, western Alberta and the Bakken. Alliance Pipeline has successfully re-contracted its firm capacity with shippers for an average contract length of approximately five years under its new services framework that commenced in December 2015. For further details, refer to *Gas Pipelines and Processing – Alliance Pipeline Recontracting.*

The Company continues to focus on expanding its Canadian Midstream footprint, primarily within the Montney and Duvernay formations, two of the most competitive natural gas and NGL plays in North America. Even during the depressed energy price environment in late 2015 and early 2016, the Montney play continues to attract active rigs. In January 2016, the Company reached agreement to purchase two operating natural gas plants (Tupper Main and Tupper West gas plants) and associated pipelines in northeastern British Columbia. The transaction closed on April 1, 2016, following required regulatory approvals. The Company also continues to pursue ultra-deep water offshore natural gas and crude oil transmission opportunities. In 2015, the Big Foot Gas Pipeline portion of the Walker Ridge Gas Gathering System (WRGGS), and the Big Foot Oil Pipeline (Big Foot Pipeline) projects were installed on the sea floor and are awaiting installation of the upstream facilities by producers. Further growth in earnings and cash flow from the Offshore business will come from the Heidelberg Oil Pipeline (Heidelberg Pipeline) which was placed into service in January 2016 and the Stampede Oil Pipeline (Stampede Pipeline) which is expected to be operational by 2018.

Enbridge's natural gas distribution business in eastern Canada is the largest in Canada with over two million customers. EGD's Greater Toronto Area (GTA) project, which was completed in March 2016, is a key component of EGD's gas supply strategy and will provide new transmission services that will enable access to mid-continent gas supplies for the utility and its customers.

In 2014, the Ontario Energy Board (OEB) approved the second generation customized IR Plan which established natural gas distribution rates over a five-year period from 2014 to 2018. A key tenet of the customized IR Plan is that it allows EGD to recover costs for significant capital investment, including the GTA project. The customized IR Plan also allows EGD an opportunity to earn above an allowed return on equity (ROE), with any return over the allowed ROE for a given year to be shared equally with customers. The customized IR Plan serves to reinforce stability of the earnings and cash flow EGD delivers to Enbridge.

Develop New Platforms for Growth and Diversification

The development of new platforms to diversify and sustain long-term growth is an important strategic priority. The Company is currently focusing its development and diversification efforts towards securing investment in additional renewable energy generation, liquefied natural gas (LNG) development, gas-fired power generation and energy marketing, as well as exploring opportunities to extend its energy delivery and generation services to select energy markets outside North America. The Company also invests in early stage energy technologies that complement the Company's core businesses.

In 2015, Enbridge continued to expand its interests in renewable power generation with the acquisitions of the 103-MW New Creek Wind Project (New Creek) in West Virginia and a 24.9% interest in the 400-MW Rampion Offshore Wind Project (Rampion Project) in the United Kingdom. Including these acquisitions, Enbridge has invested approximately $5 billion in renewable power generation and transmission since 2002.

The Company's goal is to take over full operational responsibility of its renewable power generation facilities as operating contracts with key service providers expire and if the associated economics are viable. The Company's energy marketing business also plans to expand its business through obtaining capacity on energy delivery and storage assets in strategic locations to achieve higher earnings from location, grade and time differentials.

Maintain the Foundation

Uphold Enbridge Values

Enbridge adheres to a strong set of core values that govern how it conducts its business and pursues strategic priorities, as articulated in its value statement: "Enbridge employees demonstrate integrity, safety and respect in support of our communities, the environment and each other". Employees are expected to uphold these values in their interactions with each other, customers, suppliers, landowners, community members and all others with whom the Company deals and ensure the Company's business decisions are consistent with these values. Employees and contractors are required, on an annual basis, to certify their compliance with the Company's Statement on Business Conduct.

Maintain the Company's Social License to Operate

Earning and maintaining "social license" – the acceptance by the communities in which the Company operates or is proposing new projects – is critical to Enbridge's ability to execute on its growth plans. To earn public acceptance of Enbridge and its projects, the Company is increasingly focused on building long-term relationships by understanding, accommodating and resolving public concerns related to the Company's projects and operations. The Company engages its key stakeholders through collaboration and by demonstrating openness and transparency in its communication. The Company also focuses on enhancing the Government Relations function with a goal of advocating company positions on key issues and policies that are critical to its business. The Company also builds awareness of the role energy and Enbridge play in people's lives in order to promote better understanding of the Company and its businesses.

To earn the public's trust, and to help protect and reinforce the Company's reputation with its stakeholders, Enbridge is committed to integrating Corporate Social Responsibility (CSR) into every aspect of its business. The Company defines CSR as conducting business in an ethical and responsible manner, protecting the environment and the safety of people, providing economic and other benefits to the communities in which the Company operates, supporting universal human rights and employing a variety of policies, programs and practices to manage corporate governance and ensure fair, full and timely disclosure. The Company provides its stakeholders with open, transparent disclosure of its CSR performance and prepares its annual CSR Report using the Global Reporting Initiative G4 sustainability reporting guidelines, which serve as a generally accepted framework for reporting on an organization's economic, environmental and social performance.

The Company also executes a number of specific projects, programs and initiatives to ensure the perspective of its stakeholders help guide business decision making on sustainable development issues. For example, through its Neutral Footprint Program, originally adopted in 2009, the Company committed to help reduce the environmental impact of its liquid pipeline expansion projects within five years of their occurrence by meeting goals for replacing trees, conserving land and generating kilowatt hours of green energy. During the last five years the Neutral Footprint Program has met these targets and continued to do so in 2015.

The Company has consulted with stakeholders on the development of a next generation of environmental commitments that reflect the shifting energy landscape in North America, including changing business needs, regulatory conditions and public expectations. In 2016 the Company plans to update its environmental goals to address growing public interest in its role on climate and energy issues, as well as new activities and relationships on water protection.

The Company's CSR Report can be found at http://csr.enbridge.com and progress updates on the Company's Neutral Footprint initiatives can be found in the annual CSR Report. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website is incorporated by reference in, or otherwise part of this MD&A.***

To complement community investments in its Canadian and United States operating areas, Enbridge created the energy4everyone Foundation (the Foundation) in 2009. The Foundation aims to leverage the expertise and resources of the Canadian energy industry to effect significant positive change through the delivery and deployment of affordable, reliable and sustainable energy services and technologies in communities in need around the world. To date, the Foundation has completed projects in Costa Rica, Ghana, Nicaragua, Peru and Tanzania.

Attract, Retain and Develop Highly Capable People

Investing in the attraction, retention and development of employees and future leaders is fundamental to executing Enbridge's growth strategy and creating sustainability for future success. Recently, in view of the commodity price downturn in the energy industry, the Company reduced its workforce by approximately 5% in order to maintain its competitiveness in the industry so it can continue to serve its stakeholders well and further strengthen its foundation for the future. The Company focuses on enhancing the capability of its people to maximize the potential of the organization and undertakes various activities such as offering accelerated leadership development programs, enhancing career opportunities and building change management capabilities throughout the enterprise so that projects and initiatives achieve intended benefits. Furthermore, Enbridge strives to maintain industry competitive compensation and retention programs that provide both short-term and long-term incentives.

INDUSTRY FUNDAMENTALS

SUPPLY AND DEMAND FOR LIQUIDS

Enbridge has an established and successful history of being the largest transporter of crude oil to the United States, the world's largest market. While United States' demand for Canadian crude oil production will support the use of Enbridge infrastructure for the foreseeable future, North American and global crude oil supply and demand fundamentals are shifting, and Enbridge has a role to play in this transition by developing long-term transportation options that enable the efficient flow of crude oil from supply regions to end-user markets.

As discussed in *Performance Overview – Impact of the Recent Decline in Commodity Prices*, crude oil prices fell by close to 50% in the latter half of 2014 and continued to fall to US$37 by the end of 2015, with a further decline to below US$30 in January 2016 and continuing price volatility to date. The international market for crude oil has seen a significant increase in production from North American basins and increased production from the Organization of Petroleum Exporting Countries (OPEC) in the face of slower global demand growth. The downturn in price has impacted Enbridge's liquids pipelines' customers, who have responded by reducing their exploration and development spending for 2015 and into 2016.

Notwithstanding the recent price decline, the Enbridge system has thus far continued to be highly utilized. The mainline system continues to be subject to apportionment of heavy crudes, as nominated volumes currently exceed capacity on portions of the system. Impact of the decline in crude oil prices to the financial performance of Enbridge's liquids pipelines business is expected to be relatively modest given the commercial arrangements which underpin many of the pipelines that make up the liquids system and provide a significant measure of protection against volume fluctuations. In addition, the Enbridge mainline is well positioned to continue to provide safe and efficient transportation which will enable western Canadian and Bakken production to reach attractive markets in the United States at a competitive cost relative to other alternatives. The fundamentals of oil sands production and the recent decline in crude oil prices has caused some sponsors to reconsider the timing of their upstream oil sands development projects; however, recently updated forecasts continue to reflect long-term supply growth from the WCSB, although the projected pace of growth is slower than previous forecasts as companies continue to assess the viability of certain capital investments in the current low price environment.

Over the long term, global energy consumption is expected to continue to grow, with the growth in crude oil demand primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), mainly China and India. While OECD countries, including Canada, the United States and western European nations, will experience population growth, emphasis placed on energy efficiency, conservation and a shift to lower carbon fuels, such as natural gas and renewables, will reduce crude oil demand over the long term. Accordingly, there is a strategic opportunity for North American producers to grow production to displace foreign imports and participate in the growing global demand outside North America.

In terms of supply, long-term global crude oil production is expected to continue to grow through 2035, with growth in supply primarily contributed by North America and OPEC. Growth in North America is largely driven by production from the oil sands, the Gulf of Mexico and the continued development of tight oil plays including the Bakken, Eagle Ford and Permian formations. Growth in supply from OPEC is primarily a result of a shift in OPEC's strategy from 'balancing supply' to 'competing for market share' in Asia and Europe. However, political uncertainty in certain oil producing countries, including Libya and Iraq, increases risk in those regions' supply growth forecasts and makes North America one of the most secure supply sources of crude oil. As witnessed throughout 2015 and early 2016, North American supply growth can be influenced by macro-economic factors that drive down the global crude prices. Over the longer term, North American production from tight oil plays, including the Bakken, is expected to grow as technology continues to improve well productivity and reduce costs. The WCSB, in Canada, is viewed as one of the world's largest and most secure supply sources of crude oil. However, the pace of growth in North America and level of investment in the WCSB could be tempered in future years by a number of factors including a sustained period of low crude oil prices and corresponding production decisions by OPEC, increasing environmental regulation, prolonged approval processes for new pipelines and the continuation of access restrictions to tide-water in Canada for export.

The combination of relatively flat domestic demand, growing supply and long-lead time to build pipeline infrastructure has led to a fundamental change in the North American crude oil landscape. In recent years, an inability to move increasing inland supply to tide-water markets resulted in a divergence between West Texas Intermediate (WTI) and world pricing, resulting in lower netbacks for North American producers than could otherwise be achieved if selling into global markets. The impact of price differentials has been even more pronounced for western Canadian producers as insufficient pipeline infrastructure resulted in a further discounting of Alberta crude against WTI. With a number of market access initiatives recently completed by the industry, including those introduced by Enbridge, the crude oil price differentials significantly narrowed in 2015, and resulted in higher netbacks for producers. This has resulted in crude oil moving off of alternative transportation such as rail to fill the additional pipeline capacity as it became available. However, Canadian pipeline export capacity remains essentially full, and production growth once again is increasing its use of non-pipeline transportation services. As the supply in North America continues to grow, the growth and flexibility of pipeline infrastructure will need to keep pace with the sensitive demand and supply balance. Over the longer term, the Company believes pipelines will continue to be the most cost-effective means of transportation in markets where the differential between North American and global oil prices remain narrow. Utilization of rail to transport crude is expected to be substantially limited to those markets not readily accessible by pipelines.

Enbridge's role in helping to address the evolving supply and demand fundamentals and alleviating price discounts for producers and supply costs to refiners is to provide expanded pipeline capacity and sustainable connectivity to alternative markets. As discussed in *Growth Projects – Commercially Secured Projects,* in 2015, Enbridge continued to execute its growth projects plan in furtherance of this objective.

As prices continue to remain sensitive to capacity limitations to markets, there is a heightened need to expand access to coastal markets. Details of the Company's Northern Gateway Project (Northern Gateway), a proposed pipeline system from Alberta to the coast of British Columbia, and associated marine terminal, along with the Company's other projects under development, can be found in *Other Announced Projects Under Development.*

SUPPLY AND DEMAND FOR NATURAL GAS AND NGL

Despite the recent slowing of China's economic growth, global energy demand is expected to increase over time, driven by expected economic growth from non-OECD countries. Natural gas will play an important role in meeting this energy demand and is anticipated to be one of the world's fastest growing energy sources. Most natural gas demand will stem from the need for greater power generation capacity, as natural gas is a cleaner alternative to coal, which has the largest market share for power generation. Within North America, United States natural gas demand is also expected to be driven by the next wave of gas-intensive petrochemical facilities which are expected to enter service over the next two years along with the growing volume of LNG exports, with the first cargo having sailed in late February 2016. Over the longer term, higher United States natural gas demand is expected to be driven by the industrial sector and from power generation and will be supplemented by higher exports, via LNG and to Mexico. Within Canada, natural gas demand growth is expected to be largely tied to oil sands development and growth in gas-fired power generation.

Similar to crude oil, robust North American supply from tight formations has created a demand and supply imbalance for natural gas and some NGL products. North American gas supply continues to be significantly impacted by development in the northeastern United States, primarily the prolific Marcellus shale, as well as the rapidly growing Utica shale. The abundance of supply from these shale plays has fundamentally altered natural gas flow patterns in North America. For example, flows from the United States Gulf Coast and WCSB that historically supplied eastern markets, have largely been displaced. Similar pressures are also being felt in the Midwest and southern markets. As a result, natural gas production from regions other than the northeastern United States has largely been flat or has declined over the past several years in the face of lower-cost production from the Appalachian region in addition to prolonged weak North American natural gas prices. An exception would be the recent surge in WCSB production, reaching an all-time record high in early 2016, which was triggered by the combination of new infrastructure and the connection of previously drilled wells. In the longer term, while low natural gas prices are expected to be a key driver in future natural gas demand and infrastructure growth, it is also expected that gas supply will remain ample and could respond quickly to rising demand thereby limiting price advances.

With the weak natural gas price environment over the last several years, producers had broadly shifted from dry gas drilling to developing rich gas reservoirs to take advantage of the relatively higher value of NGL inherent in the gas stream. NGL that can be extracted from liquids-rich gas streams include ethane, propane, butane and natural gasoline, which are used in a variety of industrial, commercial and other applications. However, the combined effects of much lower crude prices and regional supply imbalances for some NGL products have weakened the economics of NGL extraction to the extent that some producers have returned to drilling prolific dry gas plays which exhibit lower supply costs. Nonetheless, over the longer term, the growth in NGL demand is expected to be robust, driven largely by incremental ethane demand. Ethane is the key feedstock to the United States Gulf Coast petrochemical industry which is the world's second lowest-cost ethylene production region and is currently undergoing significant expansion. Until this new infrastructure is completed and online, ethane prices and resulting extraction margins are expected to continue to remain low due to the current oversupply, with high volumes of ethane being retained in the gas stream rather than extracted. However, the inaugural export cargo of ethane departed in March 2016 and if waterborne exports rise significantly, the ethane market will begin to tighten. Similarly, rapidly growing supplies of propane have been outpacing demand leading to record storage levels and downward pressure on prices. The outlook for abundant propane supplies in excess of domestic demand has prompted the development and expansion of export facilities for liquefied petroleum gas (LPG). Over a few short years, the United States has become the world's largest LPG exporter. Brisk LPG exports, which have reached over one million bpd at times in early 2016, have helped to reduce the inventory overhang and provide some support to propane prices. In Canada, the WCSB basin is well-situated to capitalize on the evolving NGL fundamentals over the longer term as the Montney formation in northern British Columbia and the Duvernay shale in Alberta contain significant liquids-rich resources at competitive extraction costs. While longer-term NGL fundamentals provide a positive outlook for growth, a sustained period of low crude oil prices and the related negative impact on NGL prices could temper future growth.

Weak prices for NGL, which generally trade at a percentage of crude oil prices, have also caused a reduction in investment for liquids-rich gas drilling programs and related extraction facilities, thereby limiting production growth. However, robust gas production from highly economic core areas within certain shale plays, particularly the Marcellus, is expected to continue to offset any price related production declines from other supply regions over the next year. To the extent oil prices recover, the crude-to-gas price ratio is expected to rise from current levels. Nonetheless, as the upstream industry steadily continues to realize improvements on productivity and efficiency, average break-even costs have been falling and in turn, the size of the resource base that is economic will be substantial as prices recover. This immense and readily available gas supply within North America will likely continue to limit price increases. Consequently, the crude-to-gas price ratio is expected to remain well above energy conversion value levels and continue to be supportive of NGL extraction over the longer term.

Although United States based LNG export projects have successfully executed sales contracts with pricing indexed to North American gas prices, the price for LNG in global markets has typically been more closely linked to crude oil prices, providing western Canadian producers with an opportunity to capture more favourable netbacks on LNG exports upon a recovery in crude prices, if that pricing linkage is maintained. Based on the prospect for higher global LNG demand, the large resource base in western Canada and the changing North American natural gas flow patterns discussed above, there is an expectation that projects to export LNG from the west Coast of Canada will proceed in the next decade. However, a sustained period of low crude oil prices or other changes in global supply and demand for natural gas could delay such opportunities; the combination of weaker global demand, especially within China, and the wave of new LNG export facilities coming online appear to have tightened global balances through 2020.

In response to these evolving natural gas and NGL fundamentals, Enbridge believes it is well-positioned to provide value-added solutions to producers. Alliance Pipeline traverses through the heart of key liquids-rich plays in the WCSB and is uniquely positioned to transport liquids-rich gas. Alliance Pipeline has developed new service offerings to best meet the needs of producers and shippers, and demand for transportation services on the Alliance Pipeline continues to be robust. The focus on liquids-rich gas development also creates opportunities for Aux Sable, an extraction and fractionation facility near Chicago, Illinois near the terminus of Alliance Pipeline. Enbridge is also responding to the need for regional infrastructure with additional investment in Canadian and United States midstream processing and pipeline facilities.

SUPPLY AND DEMAND FOR RENEWABLE ENERGY

The power generation and transmission network in North America is expected to undergo significant growth over the next 20 years. On the demand side, North American economic growth over the longer term is expected to drive growing electricity demand, although continued efficiency gains are expected to make the economy less energy-intensive and temper demand growth. On the supply side, impending legislation in both Canada and the United States is expected to accelerate the retirement of aging coal-fired generation plants, resulting in a requirement for significant new generation capacity. While coal and nuclear facilities will continue to be core components of power generation in North America, gas-fired and renewable energy facilities, including biomass, hydro, solar and wind, are expected to be the preferred sources to replace coal-fired generation due to their lower carbon intensities.

North American wind and solar resources fundamentals remain strong. In the United States there is over 74 gigawatts (GW) of installed wind power capacity and in Canada over 11 GW of capacity. Solar resources in southwestern states such as Arizona, California and Nevada are considered to be some of the best in the world for large-scale solar plants and the United States currently has over 27 GW of installed solar photovoltaic capacity. In addition, in late 2015, the United States passed legislation extending the availability of certain Federal tax incentives which have supported the profitability of wind and solar projects. However, expanding renewable energy infrastructure in North America is not without challenges. Growing renewable generation capacity is expected to necessitate substantial capital investment to upgrade existing transmission systems or, in many cases, build new transmission lines, as these high quality wind and solar resources are often found in regions that are not in close proximity to markets. In the near-term, uncertainty over the availability of tax or other government incentives in various jurisdictions, the ability to secure long-term power purchase agreements (PPA) through government or investor-owned power authorities and low market prices of electricity may hinder the pace of future new renewable capacity development. However, continued improvement in technology and manufacturing capacity in the past few years has reduced capital costs associated with renewable energy infrastructure and has also improved yield factors of power generation assets. These positive developments are expected to render renewable energy more competitive and support ongoing investment over the long term.

In Europe the future outlook for renewable energy, especially from offshore wind in countries with long coastlines and densely populated areas, is very positive. Over EUR250 billion of investment is forecast in the European offshore wind industry up to 2030. There is also wide public support for carbon reduction targets and broader adoption of renewable generation across all governmental levels. Furthermore, governments in Europe look to rationalize the contribution of nuclear power to the overall energy mix, which has resulted in an increased focus on alternative sources such as large scale offshore wind.

Enbridge continues to expand its renewable asset footprint and is one of Canada’s largest wind and solar power generators. In late 2015, Enbridge announced acquisitions of the 103-MW New Creek in West Virginia and a 24.9% interest in the 400-MW Rampion Project in the United Kingdom. Including these acquisitions, Enbridge has invested approximately $5 billion in renewable power generation and transmission since 2002. The Company will continue to seek new opportunities to expand its power generation business, growing its portfolio by investing in assets that meet its investment criteria.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

A key focus of Enbridge's corporate strategy is the successful execution of its growth capital program. In 2015, Enbridge successfully placed into service approximately $8 billion of growth projects across several business units. Enbridge's remaining portfolio of approximately $18 billion of growth projects is expected to be placed into service by 2019, with approximately $2 billion expected to come into service during 2016.

Over the past few years, Enbridge's growth capital program has been anchored by three major market access initiatives, supported by several mainline system expansion and regional infrastructure projects that are designed to ensure that there is sufficient capacity to support these new market access extensions. The three major market access initiatives are:

- the Gulf Coast Access Program;
- the Eastern Access Program; and
- the Light Oil Market Access Program.

The Gulf Coast Access Program included the Seaway Pipeline, Seaway Crude Pipeline System Twin (Seaway Pipeline Twin) and Flanagan South Pipeline (Flanagan South) projects that were completed in 2014, as well as elements of the Canadian Mainline and Lakehead System Mainline expansions. These projects have increased access to refinery markets in the Gulf Coast. In 2015, Enbridge completed its Gulf Coast Access Program with the completion of a phase of the Mainline Expansion project that increased the capacity of the liquids mainline system by 230,000 bpd.

The Company's Eastern Access Program has allowed for greater access for crude oil into Chicago, further east into Toledo and ultimately into Ontario and Quebec. The Eastern Access Program included the Company's Toledo pipeline expansion, Line 9 reversal, the Spearhead North pipeline expansion, Line 6B replacement and Line 5 expansion. With the reversal of Line 9B and placement of this 300,000 bpd line into service in December 2015, the Company completed the Eastern Access Program in 2015.

Finally, the Light Oil Market Access Program brings together a group of projects to transport an increasing supply of light oil from Canada and the Bakken and supplement the Eastern Access Program through the upsizing of Line 9B and the Line 6B capacity expansion. The Light Oil Market Access Program also includes Southern Access Extension, Sandpiper, Canadian Mainline System Terminal Flexibility and Connectivity, Spearhead North Twin (Line 78) and Southern Access expansion included within the Lakehead System Mainline Expansion. The Company made significant progress on this program during 2015 completing the capacity expansion portion of the Line 9B project and the Southern Access Extension, both of which were placed into service in December 2015. Additionally, EEP further expanded the capacity of the Lakehead System between Superior, Wisconsin and Griffith, Indiana through the completion of phases of the Southern Access expansion in May 2015 and October 2015, as well as the completion of the Spearhead North Twin (Line 78) in November 2015.

In keeping with the Company's strategic priority to develop new platforms to diversify and sustain long-term growth, Enbridge continued to expand its renewable energy generation capacity in 2015. The Keechi Wind Project (Keechi) entered service in January 2015, increasing Enbridge's net operating renewable power generating capacity to nearly 1,800-MW. Enbridge also announced acquisitions of the 103-MW New Creek in West Virginia and a 24.9% interest in the 400-MW Rampion Project in the United Kingdom, which are expected to be placed into service in 2016 and 2018, respectively, increasing Enbridge's interests to nearly 2,000 MW of net renewable and alternative energy generating capacity.

The following table summarizes the status of the Company's commercially secured projects, organized by business segment. Expenditures to date reflect total cumulative expenditures incurred from inception of the project to December 31, 2015. The project narratives that follow the table reflect the status of the projects up to February 19, 2016, the date of the original filing of the Company's MD&A for the year ended December 31, 2015. For a current description of project updates since February 19, 2016, refer to the Company's MD&A for the three months ended March 31, 2016 filed on May 12, 2016.

	Estimated Capital Cost[1,6]	Expenditures to Date[2]	Expected In-Service Date[6]	Status[6]
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Southern Access Extension	US$0.6 billion	US$0.6 billion	2015	Complete
2. Eastern Access Line 9 Reversal and Expansion (the Fund Group)	$0.8 billion	$0.8 billion	2013-2015 (in phases)	Complete
3. Eastern Access (EEP)[3]	US$2.7 billion	US$2.4 billion	2013-2016 (in phases)	Under construction
4. Canadian Mainline Expansion (the Fund Group)	$0.7 billion	$0.7 billion	2015	Complete
5. Surmont Phase 2 Expansion (the Fund Group)	$0.3 billion	$0.3 billion	2014-2015 (in phases)	Complete
6. Canadian Mainline System Terminal Flexibility and Connectivity (the Fund Group)	$0.7 billion	$0.7 billion	2013-2015 (in phases)	Complete
7. Woodland Pipeline Extension (the Fund Group)	$0.7 billion	$0.7 billion	2015	Complete
8. Sunday Creek Terminal Expansion (the Fund Group)	$0.2 billion	$0.2 billion	2015	Complete
9. Edmonton to Hardisty Expansion (the Fund Group)	$1.6 billion	$1.6 billion	2015 (in phases)	Complete
10. AOC Hangingstone Lateral (the Fund Group)	$0.2 billion	$0.2 billion	2015	Complete
11. JACOS Hangingstone Project (the Fund Group)	$0.2 billion	$0.1 billion	2016	Under construction
12. Regional Oil Sands Optimization Project (the Fund Group)	$2.6 billion	$1.6 billion	2017	Under construction
13. Norlite Pipeline System (the Fund Group)[4]	$1.3 billion	$0.2 billion	2017	Under construction
14. Lakehead System Mainline Expansion (EEP)[3]	US$2.4 billion	US$2.0 billion	2014-2019 (in phases)	Under construction
15. Canadian Line 3 Replacement Program (the Fund Group)	$4.9 billion	$0.9 billion	2019	Pre-construction
16. U.S. Line 3 Replacement Program (EEP)	US$2.6 billion	US$0.3 billion	2019	Pre-construction
17. Sandpiper Project (EEP)[5]	US$2.6 billion	US$0.7 billion	2019	Pre-construction
GAS DISTRIBUTION				
18. Greater Toronto Area Project	$0.9 billion	$0.8 billion	2016 (in phases)	Under construction
GAS PIPELINES AND PROCESSING				
19. Beckville Cryogenic Processing Facility (EEP)	US$0.2 billion	US$0.2 billion	2015	Complete
20. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-TBD (in phases)	Complete
21. Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	TBD	Complete
22. Eaglebine Gathering (EEP)	US$0.2 billion	US$0.1 billion	2015-TBD (in phases)	Complete (Phase I)
23. Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Complete

	Estimated Capital Cost[1,6]	Expenditures to Date[2]	Expected In-Service Date[6]	Status[6]
24. Tupper Main and Tupper West Gas Plants	$0.5 billion	No significant expenditures to date	2016	Acquisition in progress
25. Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Under construction
26. Stampede Oil Pipeline	US$0.2 billion	No significant expenditures to date	2018	Pre-construction
GREEN POWER AND TRANSMISSION				
27 Keechi Wind Project	US$0.2 billion	US$0.2 billion	2015	Complete
28 New Creek Wind Project	US$0.2 billion	No significant expenditures to date	2016	Pre-Construction
29 Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.2 billion (£0.10 billion)	2018	Under construction

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

2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2015.

3 The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP.

4 The Company will construct and operate the Norlite Pipeline System (Norlite). Keyera Corp. (Keyera) will fund 30% of the project.

5 The Company will construct and operate Sandpiper. Marathon Petroleum Corporation (MPC) will fund 37.5% of the project.

6 This information reflects project information as of February 19, 2016, the date of the original filing of the Company's MD&A for the year ended December 31, 2015. For current information, refer to the Company's MD&A for the three months ended March 31, 2016 filed on May 12, 2016.

Risks related to the development and completion of growth projects are described under *Risk Management and Financial Instruments – General Business Risks.* As part of the Canadian Restructuring Plan, the commercially secured growth programs embedded within EPI and EPAI were transferred to the Fund Group. Enbridge continues to oversee the execution of the growth program, as well as manage the operations and future development opportunities of these assets. Reference to "the Company" in this *Growth Projects – Commercially Secured Projects* section includes activities performed by the Fund Group, or on its behalf by Enbridge, following the completion of the Canadian Restructuring Plan.

Liquids Pipelines

1 Southern Access Extension
2 Eastern Access Line 9 Reversal and Expansion (the Fund Group)
3 Eastern Access (EEP)
4 Canadian Mainline Expansion (the Fund Group)
5 Surmont Phase 2 Expansion (the Fund Group)
6 Canadian Mainline System Terminal Flexibility and Connectivity (the Fund Group)
7 Woodland Pipeline Extension (the Fund Group)
8 Sunday Creek Terminal Expansion (the Fund Group)
9 Edmonton to Hardisty Expansion (the Fund Group)
10 AOC Hangingstone Lateral (the Fund Group)
11 JACOS Hangingstone Project (the Fund Group)
12 Regional Oil Sands Optimization Project (the Fund Group)
13 Norlite Pipeline System (the Fund Group)
14 Lakehead System Mainline Expansion (EEP)
15 Canadian Line 3 Replacement Program (the Fund Group)
16 U.S. Line 3 Replacement Program (EEP)
17 Sandpiper Project (EEP)

- Current Assets
- Growth Projects
- The Fund Group[1]
- The Fund Group Legacy Assets
- Enbridge Energy Partners, L.P.

1 Effective September 1, 2015, Enbridge transferred its Canadian Liquids Pipelines business to the Fund Group. For further details, refer to *Canadian Restructuring Plan.*

LIQUIDS PIPELINES

Southern Access Extension

The Southern Access Extension joint venture involved the construction of a new 265-kilometre (165-mile), 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, for an initial capacity of approximately 300,000 bpd, as well as additional tankage and two new pump stations. The project was placed into service in December 2015 and the Company's share of the total capital cost was approximately US$0.6 billion.

Eastern Access

The Eastern Access initiative includes a series of Fund Group and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada.

Eastern Access (the Fund Group)

Projects undertaken by the Company include a reversal of Line 9A and expansion of the Toledo Pipeline, both completed in 2013, as well as the reversal of Line 9B and expansion of Line 9 (together, Line 9), which was placed into service in December 2015.

The Company completed the reversal of its 240,000 bpd Line 9B from Westover, Ontario to Montreal, Quebec to serve refineries in that province. The Line 9B reversal was initially expected to be completed at an estimated cost of approximately $0.3 billion. Following an open season held on the Line 9B reversal project, further commitments were received that required additional delivery capacity into Ontario and Quebec, resulting in the Line 9 capacity expansion project. The Line 9 capacity expansion increased the annual capacity of Line 9 from 240,000 bpd to 300,000 bpd at an estimated cost of approximately $0.1 billion.

The Line 9B Reversal and Line 9 Capacity Expansion projects were approved by the National Energy Board (NEB) in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B Reversal and Line 9 Capacity Expansion Project. On October 23, 2014, the Company responded to the NEB describing the Company's rigorous approach to risk management and isolation valve placement. On February 6, 2015, the NEB approved Conditions 16 and 18, the two conditions in the NEB's order requiring approval, and the Company filed for a Leave to Open (LTO), which is a prerequisite to allowing the operation of the project. In its February approval, the NEB also imposed additional obligations on the Company that directed the Company to take a “life-cycle” approach to water crossings and valves, requiring it to perform ongoing analysis to ensure optimal protection of the area's water resources. On June 18, 2015, the NEB approved the LTO application and issued a separate order imposing further conditions requiring the Company to perform hydrostatic tests of selected segments of the pipeline. The Company filed its hydrostatic test plan with the NEB on July 23, 2015, which was approved on July 27, 2015. Hydrostatic testing was completed and the Company submitted the test results to the NEB in September 2015. On September 30, 2015 the NEB confirmed that the hydrostatic tests successfully met their criteria. Line-fill commenced in late October 2015 and the pipeline was placed into service in December 2015.

Costs related to conditions imposed by the NEB, including valve placement and hydrostatic testing, increased the total project cost at in-service to $0.8 billion, inclusive of costs related to the previously mentioned Line 9A reversal. Pursuant to various agreements with shippers, the Company is able to recover from shippers the full costs of compliance with NEB imposed hydrostatic testing and the valve replacement program.

On July 31, 2014, the Company filed an application for tolls on Line 9. After complaints from shippers on Line 9 were filed with the NEB with respect to the inclusion of mainline surcharges in the Line 9 toll, the NEB approved the tolls on an interim basis to allow for time to engage shippers in further discussions to attempt to resolve the outstanding issues. On January 30, 2015, the NEB convened a hearing to consider the matter. In response to a request from the Company that was supported by the shippers, the hearing was suspended to allow the Company and shippers to engage in further discussions to resolve the outstanding issues. In the third quarter of 2015, the Company and the shippers came to an agreement to recover mainline surcharges in the Line 9 toll.

Eastern Access (EEP)
Projects undertaken by EEP included an expansion of Line 5 and of the United States mainline involving the Spearhead North Pipeline (Line 62), both completed in 2013, and replacement of additional segments of Line 6B, completed in 2014. The cost of these projects was approximately US$2.4 billion.

Additionally, the Eastern Access initiative also includes a further upsizing of EEP's Line 6B. The Line 6B capacity expansion from Griffith, Indiana to Stockbridge, Michigan will increase capacity from 500,000 bpd to 570,000 bpd and will include pump station modifications at the Griffith, Niles and Mendon stations, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. The Line 6B capacity expansion is now expected to be placed into service in mid-2016 at an estimated cost of approximately US$0.3 billion.

The total estimated cost of the projects being undertaken by EEP as part of the Eastern Access initiative, including the Line 6B capacity expansion project, is approximately US$2.7 billion, with expenditures to date of approximately US$2.4 billion. The Eastern Access projects undertaken by EEP are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to Enbridge Energy, Limited Partnership (EELP) for its interests in the Eastern Access projects until the second quarter of 2016. EELP holds partnership interests in assets that are jointly funded by Enbridge and EEP, including the Eastern Access projects. In return, Enbridge's capital funding contribution requirements to the Eastern Access projects will be netted against its foregone cash distribution during this period.

Canadian Mainline Expansion (the Fund Group)
The Company undertook an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consisted of two phases that involved the addition of pumping horsepower to raise the capacity of the Alberta Clipper line from 450,000 bpd to 800,000 bpd. The initial phase to increase capacity from 450,000 bpd to 570,000 bpd was completed in the third quarter of 2014 at an estimated capital cost of approximately $0.2 billion. The second phase to increase capacity from 570,000 bpd to 800,000 bpd was completed in July 2015 at an expected cost of approximately $0.5 billion. The total cost of the entire expansion was approximately $0.7 billion. Receipt of the final regulatory approval on EEP's portion of the mainline system expansion has been delayed. EEP continues to work with regulatory authorities; however, the timing of the federal regulatory approval cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with this delay.

Surmont Phase 2 Expansion (the Fund Group)
In 2013, the Company entered into a terminal services agreement with ConocoPhillips Canada Resources Corp. (ConocoPhillips) and Total E&P Canada Ltd. (together, the ConocoPhillips Partnership) to expand the Cheecham Terminal to accommodate incremental bitumen production from Surmont's Phase 2 expansion. The Company constructed two new 450,000 barrel blend tanks and converted an existing tank from blend to diluent service. The expansion occurred in two phases with the blended product system placed into service in November 2014 and the diluent system placed into service in March 2015 at a total cost of approximately $0.3 billion.

Canadian Mainline System Terminal Flexibility and Connectivity (the Fund Group)
As part of the Light Oil Market Access Program initiative, the Company undertook the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The modifications comprised of upgrading existing booster pumps, installing additional booster pumps and adding new tank line connections. These projects had varying completion dates from 2013 through the second quarter of 2015. The total cost of the project was approximately $0.7 billion.

Woodland Pipeline Extension (the Fund Group)
The joint venture Woodland Pipeline Extension Project extended the Woodland Pipeline south from the Company's Cheecham Terminal to its Edmonton Terminal. The extension is a 388-kilometre (241-mile), 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. The project was completed and placed into service in July 2015. The Company's share of the project costs was approximately $0.7 billion.

Sunday Creek Terminal Expansion (the Fund Group)
In 2014, the Company announced the construction of additional facilities at its existing Sunday Creek Terminal, located in the Christina Lake area of northern Alberta, to support production growth from the Christina Lake oil sands project operated by Cenovus Energy Inc. and jointly owned with ConocoPhillips. The expansion included development of a new site adjacent to the existing terminal, construction of a new 350,000 barrel tank with associated piping, pumps and measurement equipment, as well as civil construction work for a future tank. The project was placed into service in August 2015 at an approximate cost of $0.2 billion.

Edmonton to Hardisty Expansion (the Fund Group)
The expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta included 181 kilometres (112 miles) of new 36-inch diameter pipeline and provides an initial capacity of approximately 570,000 bpd, expandable to 800,000 bpd. The new line generally follows the same route as the Company's existing Line 4 pipeline. Also included in the project scope were connections into existing infrastructure at the Hardisty Terminal and new terminal facilities in Edmonton, Alberta which include five new 500,000 barrel tanks. The new pipeline was placed into service in April 2015, with additional tankage requirements completed in December 2015. The project was placed into service at a cost of approximately $1.6 billion.

AOC Hangingstone Lateral (the Fund Group)
In 2013, the Company entered into an agreement with Athabasca Oil Corporation (AOC) to provide pipeline and terminalling services to the proposed AOC Hangingstone Oil Sands Project (AOC Hangingstone) in Alberta. Phase I of the project involved the construction of a new 49-kilometre (31-mile), 16-inch diameter pipeline from the AOC Hangingstone project site to the Company's existing Cheecham Terminal and related facility modifications at Cheecham, Alberta. This phase of the project provides an initial capacity of 16,000 bpd and was placed into service in December 2015 at a cost of approximately $0.2 billion. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total capacity of 76,000 bpd.

JACOS Hangingstone Project (the Fund Group)
The Company is undertaking the construction of facilities and it will provide transportation services to the Japan Canada Oil Sands Limited (JACOS) Hangingstone Oil Sands Project (JACOS Hangingstone). JACOS and Nexen Energy ULC, a wholly-owned subsidiary of China National Offshore Oil Corporation Limited, are partners in the project which is operated by JACOS. The Company is constructing a new 53-kilometre (33-mile), 12-inch lateral pipeline to connect the JACOS Hangingstone project site to the Company's existing Cheecham Terminal. The project, which will provide capacity of 40,000 bpd, is expected to enter service by the end of 2016. The estimated cost of the project is approximately $0.2 billion, with expenditures to date of approximately $0.1 billion.

Regional Oil Sands Optimization Project (the Fund Group)
In March 2015, the Company announced a plan to optimize previously announced expansions of its Regional Oil Sands System currently in execution. The Company previously announced the Wood Buffalo Extension, which includes the construction of a 30-inch pipeline, from the Company's Cheecham Terminal to its Battle River Terminal at Hardisty, Alberta and associated terminal upgrades, and the Athabasca Pipeline Twin, which consists of the twinning of the southern section of the Athabasca Pipeline with a 36-inch diameter pipeline from Kirby Lake, Alberta to its Hardisty crude oil hub.

The optimization plan, which has been agreed to with the affected shippers, including Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (the Fort Hills Partners), will enable deferral of the southern segment of the Wood Buffalo Extension by connecting it to the Athabasca Pipeline Twin. The optimization involves the upsize of a 100-kilometre (60-mile) segment of the Wood Buffalo Extension between Cheecham, Alberta and Kirby Lake, Alberta from a 30-inch diameter pipeline to a 36-inch diameter pipeline, which will now connect to the origin of the Athabasca Pipeline Twin at Kirby Lake, Alberta. The capacity of the Athabasca Pipeline Twin will be expanded from 450,000 bpd to 800,000 bpd through additional horsepower.

The definitive cost estimate of the Wood Buffalo Extension was finalized at approximately $1.8 billion before optimization. As a result of the optimization, the cost estimate to complete the integrated Wood Buffalo Extension and Athabasca Pipeline Twin projects is expected to decrease from approximately $3.0 billion to approximately $2.6 billion. Expenditures on the joint projects to date are approximately $1.6 billion.

The integrated Wood Buffalo Extension and Athabasca Pipeline Twin will transport diluted bitumen from the proposed Fort Hills Partners' oil sands project (Fort Hills Project) in northeastern Alberta, as well as from oil sands production from Suncor Energy Oil Sands Limited Partnership (Suncor Partnership) in the Athabasca region. The Wood Buffalo Extension and the Athabasca Pipeline Twin will ship blended bitumen from the Fort Hills Project and have an expected 2017 in-service date. The Athabasca Pipeline Twin will also ship blended bitumen from the Cenovus Christina Lake Steam Assisted Gravity Drainage project near the origin of the Athabasca Pipeline Twin.

Norlite Pipeline System (the Fund Group)
The Company is undertaking the development of Norlite, a new industry diluent pipeline originating from Edmonton, Alberta to meet the needs of multiple producers in the Athabasca oil sands region. The scope of the project was increased to a 24-inch diameter pipeline, which will provide an initial capacity of approximately 224,000 bpd of diluent, with the potential to be further expanded to approximately 400,000 bpd of capacity with the addition of pump stations. Norlite will be anchored by throughput commitments from the Fort Hills Partners for production from the proposed Fort Hills Project and from Suncor Partnership's proprietary oil sands production. Norlite will involve the construction of a new 449-kilometre (278-mile) pipeline from the Company's Stonefell Terminal to its Cheecham Terminal with an extension to Suncor Partnership's East Tank Farm, which is adjacent to the Company's existing Athabasca Terminal. Under an agreement with Keyera, Norlite has the right to access certain existing capacity on Keyera's pipelines between Edmonton, Alberta and Stonefell, Alberta and, in exchange, Keyera has elected to participate in the new pipeline infrastructure project as a 30% non-operating owner. Norlite is expected to be completed in 2017 at an estimated cost of approximately $1.3 billion, with expenditures to date of approximately $0.2 billion.

Lakehead System Mainline Expansion (EEP)
The Lakehead System Mainline Expansion includes several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States border, near Neche, North Dakota to Flanagan, Illinois. These projects are in addition to expansions of the Lakehead System mainline being undertaken as part of the Eastern Access initiative and include the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61) and the construction of the Spearhead North Twin (Line 78).

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase increased capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. The second phase increased capacity from 570,000 bpd to 800,000 bpd at an estimated capital cost of approximately US$0.2 billion. The initial phase was completed in the third quarter of 2014 and the second phase was completed in July 2015. Both phases of the Alberta Clipper expansion required only the addition of pumping horsepower with no pipeline construction and are subject to regulatory approvals, including an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd. EEP continues to work with regulatory authorities; however, the timing of receipt of the amendment to the Presidential border crossing permit to allow for increased flow on Alberta Clipper across the border cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining this amendment.

In November 2014, several environmental and Native American groups filed a complaint in the United States District Court in Minnesota (the Court) against the United States Department of State (DOS). The Complaint alleges, among other things, that the DOS is in violation of the United States' National Environmental Policy Act by acquiescing in the Company's use of permitted cross border capacity on other pipelines to achieve the transportation of amounts in excess of Alberta Clipper's current permitted capacity while the review and approval of the Company's application to the DOS to increase Alberta Clipper's permitted cross border capacity is still pending. On December 9, 2015 the Court ruled that the United States' State Department's interpretation of Enbridge's Presidential permits is not reviewable by a federal court on constitutional grounds.

The scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of phases that require only the addition of pumping horsepower with no pipeline construction. The initial phase to increase the capacity from 400,000 bpd to 560,000 bpd was completed in August 2014 at an estimated capital cost of approximately US$0.2 billion. EEP further expanded the pipeline capacity to 800,000 bpd in May 2015 at an estimated capital cost of approximately US$0.4 billion. Additional tankage is expected to cost approximately US$0.4 billion with various completion dates that began in the third quarter of 2015 and are expected to continue through the third quarter of 2016. In the first quarter of 2015, the Company, in conjunction with shippers, decided to delay the in-service date of a further expansion phase to increase the pipeline capacity to 1,200,000 bpd at an estimated capital cost of approximately US$0.5 billion, to align more closely with the anticipated in-service date for Sandpiper. In October 2015, a portion of this phase was placed into service early to address capacity constraints, increasing the pipeline capacity to 950,000 bpd. The remaining capacity is now expected to be in service in early 2019 in line with the expected in-service date of Sandpiper.

As part of the Light Oil Market Access Program, EEP expanded the capacity of the Lakehead System between Flanagan, Illinois and Griffith, Indiana by constructing a 127-kilometre (79-mile), 36-inch diameter twin of the existing Spearhead North Pipeline (Line 62), with an initial capacity of 570,000 bpd. The completed Spearhead North Twin (Line 78) project was placed into service in November 2015 at a cost of approximately US$0.5 billion.

The projects collectively referred to as the Lakehead System Mainline Expansion are now expected to cost approximately US$2.4 billion, with expenditures incurred to date of approximately US$2.0 billion. EEP will operate the project on a cost-of-service basis. The Lakehead System Mainline Expansion is funded 75% by Enbridge and 25% by EEP. EEP has the option to increase its economic interest held by up to an additional 15% at cost. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to EELP for its interests in the Lakehead System Mainline Expansion until the second quarter of 2016. EELP holds partnership interests in assets that are jointly funded by Enbridge and EEP, including the Lakehead System Mainline Expansion. In return, Enbridge's capital funding contribution requirements to the Lakehead System Mainline Expansion will be netted against its foregone cash distribution during this period.

Line 3 Replacement Program

In 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the overall system, enhance flexibility and allow the Company to optimize throughput on the mainline system's overall western Canada export capacity. The L3R Program is expected to achieve capacity of approximately 760,000 bpd.

Canadian Line 3 Replacement Program (the Fund Group)

The Canadian L3R Program will complement existing integrity programs by replacing approximately 1,084 kilometres (673 miles) of the remaining line segments of the existing Line 3 pipeline between Hardisty, Alberta and Gretna, Manitoba.

With the NEB hearing for the Canadian L3R Program application ending in December 2015, the application record is now closed with Final Conditions and a recommendation to the Federal Cabinet (the Cabinet) expected by the end of the first quarter of 2016. A decision by the Cabinet was expected to be issued by July 2016 per guidelines; however, the Company is awaiting confirmation following the Federal Government's January 27, 2016 announcement that outside of the NEB process for industry projects, it has directed Federal agencies to conduct assessments of direct and upstream greenhouse gas emissions and incremental consultation with affected communities and Indigenous peoples. Depending on the scope of this new process, the expected timeline for final regulatory approval to commence construction could be extended.

The Company has reached a settlement agreement with landowner associations representing Line 3 landowners in Canada and as a result these parties have withdrawn from the hearing process and have expressed their support for the project.

Subject to regulatory and other approvals, the Canadian L3R Program is now targeted to be completed in early 2019 at an estimated capital cost of approximately $4.9 billion, with expenditures to date of approximately $0.9 billion. With a delay in construction, the cost of this project is expected to increase. The Company continues to review the estimated cost of this project. Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the CTS.

United States Line 3 Replacement Program (EEP)
EEP expects to undertake the United States portion of the L3R Program (U.S. L3R Program) which will complement existing integrity programs by replacing approximately 576 kilometres (358 miles) of the remaining line segments of the existing Line 3 pipeline between Neche, North Dakota and Superior, Wisconsin.

The Minnesota Public Utilities Commission (MNPUC) found both the Certificate of Need and Route Permit applications for the U.S. L3R Program through Minnesota to be complete. The MNPUC had sent the Certificate of Need application to the Administrative Law Judge (ALJ) for a pre-hearing meeting to establish a schedule. With respect to the Route Permit, the Minnesota Department of Commerce held public scoping meetings in August 2015. As a result of the Court of Appeals decision in the Sandpiper docket, the ALJ requested direction on how to proceed with the Certificate of Need process for Line 3. On February 1, 2016 the MNPUC issued a written order (the U.S. L3R Order) joining the Line 3 Certificate of Need and Route Permit dockets, requiring the Department of Commerce to prepare an Environmental Impact Statement before Certificate of Need and Route Permit processes commence and sent the cases to the Office of Administrative Hearings with direction to re-start the process. The Company believes that the directions from the MNPUC in most of the decisions set out in the U.S. L3R Order were consistent with expectations and provide clarity on process matters; however, Enbridge believes that the requirement to have a final Environmental Impact Statement prior to beginning the Certificate of need and Route Permit processes is unprecedented and contrary to Minnesota law. On February 5, 2016 EEP filed a Petition for Reconsideration of this aspect of the U.S. L3R Order. If upheld, the U.S. L3R Order will result in further delays in the processing of the applications and an increase in the cost of the project.

Subject to regulatory and other approvals, the U.S. L3R Program is now expected to be completed in early 2019 at an estimated capital cost of approximately US$2.6 billion, with expenditures to date of approximately US$0.3 billion. The Company continues to review the impact of the U.S. L3R Order on the U.S. L3R Program's schedule and cost estimates. The U.S. L3R Program will be jointly funded by Enbridge and EEP at participation levels that are subject to finalization. EEP will recover the costs based on its existing Facilities Surcharge Mechanism with the initial term of the agreement being 15 years. For the purpose of the toll surcharge, the agreement specifies a 30-year recovery of the capital based on a cost of service methodology.

Sandpiper Project (EEP)
As part of the Light Oil Market Access Program initiative, EEP plans to undertake Sandpiper, which will expand and extend EEP's North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will

involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, by adding 250,000 bpd of capacity between Tioga and Berthold, North Dakota and 225,000 bpd of capacity between Berthold and Clearbrook, both with new 24-inch diameter pipelines, as well as adding 375,000 bpd of capacity between Clearbrook and Superior with a new 30-inch diameter pipeline.

EEP is in the process of obtaining the appropriate permits for constructing Sandpiper in Minnesota. The project requires both a Certificate of Need and Route Permit from the MNPUC. On August 3, 2015, the MNPUC issued an order granting a Certificate of Need and a separate order restarting the Route Permit proceedings. On September 14, 2015 the Minnesota Court of Appeals reversed the MNPUC's Certificate of Need order stating that an Environmental Impact Statement must be prepared prior to reaching a final decision in cases where proceedings have been separated and handled sequentially. On January 11, 2016 the MNPUC issued a written order (the Sandpiper Order) re-joining the Certificate of Need and Route Permit process, requiring the Department of Commerce to commence preparation of an Environmental Impact Statement, ordering the Office of Administrative Hearings to recommence processing the Certificate of Need and Route Permit applications but to take judicial notice of the record already developed for the Certificate of Need, and to require that a final Environmental Impact Statement be issued before the Certificate of Need and Route Permit processes commence. The Company believes that the directions from the MNPUC in most of the decisions set out in the Sandpiper Order were consistent with expectations and provide clarity on process matters; however, Enbridge believes that the requirement to have a final Environmental Impact Statement prior to beginning the Certificate of Need and Route Permit processes is unprecedented and contrary to Minnesota law. On February 1, 2016, EEP filed a Petition for Reconsideration of this aspect of the Sandpiper Order. If upheld, the Sandpiper Order will result in delays in the processing of the applications and an increase in the cost of the project.

Subject to regulatory and other approvals, Sandpiper is now expected to be completed in early 2019 at an estimated capital cost of approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.7 billion. The Company continues to review the impact of the Sandpiper Order on the project's schedule and cost estimates.

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

GAS DISTRIBUTION

Greater Toronto Area Project

EGD is undertaking the expansion of its natural gas distribution system in the GTA to meet the demands of growth and to continue the safe and reliable delivery of natural gas to current and future customers. The GTA project involves the construction of two new segments of pipeline, a 27-kilometre (17-mile), 42-inch diameter pipeline (Western segment) and a 23-kilometre (14-mile), 36-inch diameter pipeline (Eastern segment), both of which are now expected to enter service by the end of the first quarter of 2016, as well as related facilities to upgrade the existing distribution system in Toronto, Ontario, that delivers natural gas to several municipalities in the GTA. The project is now expected to cost approximately $0.9 billion due to greater complexity in the construction and requirements from government and permitting agencies. Expenditures incurred to date are approximately $0.8 billion.

Gas Distribution

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GAS PIPELINES AND PROCESSING

Beckville Cryogenic Processing Facility (EEP)

EEP and its partially-owned subsidiary, MEP, have constructed a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas. The Beckville Plant offers incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where the East Texas system is located. The Beckville Plant has a natural gas processing capability of 150 million cubic feet per day (mmcf/d) and is expected to produce 8,500 bpd of NGL. The Beckville Plant was placed into service in May 2015 at a cost of approximately US$0.2 billion.

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California, and their co-owners, to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, the Company has constructed and will own and operate the WRGGS to provide natural gas gathering services to the Chevron operated 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 metres (7,000 feet), with capacity of 100 mmcf/d. The Jack St. Malo portion of the WRGGS was placed into service in December 2014. The Big Foot Gas Pipeline portion of the WRGGS has been installed on the sea floor and is awaiting Big Foot platform installation, which has been delayed due to installation problems experienced by Chevron. Chevron continues to investigate the extent of the delay. The Company began collecting certain fees in the fourth quarter of 2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

Big Foot Oil Pipeline

Under agreements with Chevron, Statoil Gulf of Mexico LLC and Marubeni Oil & Gas (USA) Inc., the Company has completed the installation on the sea floor of a 64-kilometre (40-mile), 20-inch oil pipeline with a capacity of 100,000 bpd from Chevron's Big Foot ultra-deep water development in the Gulf of Mexico. This crude oil pipeline project is complementary to the Company's undertaking of the WRGGS construction, discussed above. Upon completion of the project, the Company will operate the Big Foot Pipeline, located approximately 274 kilometres (170 miles) south of the coast of Louisiana. As noted above, although the Big Foot ultra-deep water development has been delayed, the Company began collecting certain fees in the fourth quarter of 2015. The estimated capital cost of the project is approximately US$0.2 billion, with expenditures to date of approximately US$0.2 billion.

Gas Pipelines and Processing

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25 Aux Sable Extraction Plant Expansion

26 Stampede Oil Pipeline

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- Growth Projects
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Eaglebine Gathering (EEP)
In February 2015, EEP and MEP announced their entry into the emerging Eaglebine shale play in East Texas through two transactions totalling approximately US$0.2 billion. EEP and MEP completed construction of the Ghost Chili pipeline project, consisting of a lateral and associated facilities that create gathering capacity of over 50 mmcf/d for rich natural gas to be delivered from Eaglebine production areas to their complex of cryogenic processing facilities in East Texas. The initial facilities were placed into service in October 2015. EEP also expects to construct the Ghost Chili Extension Lateral to fully utilize the gathering capacity with the rest of EEP's processing assets when additional development in the basin supports it. Given the proximity of EEP's existing East Texas assets, this expansion into Eaglebine will allow EEP to offer gathering and processing services while leveraging assets on its existing footprint. MEP also acquired New Gulf Resources, LLC's midstream business in Leon, Madison and Grimes Counties, Texas. The acquisition consists of a natural gas gathering system that is currently in operation. Expenditures incurred to date are approximately US$0.1 billion.

Heidelberg Oil Pipeline
The Company constructed and owns and operates a crude oil pipeline in the Gulf of Mexico which connects the Heidelberg development, operated by Anadarko Petroleum Corporation, to an existing third party system. Heidelberg Pipeline, a 58-kilometre (36-mile), 20-inch diameter pipeline with capacity of 100,000 bpd, originates in Green Canyon Block 860, approximately 320 kilometres (200 miles) southwest of New Orleans, Louisiana at an estimated depth of 1,600 metres (5,300 feet). Heidelberg Pipeline was placed into service in January 2016 at an approximate cost of US$0.1 billion.

Tupper Main and Tupper West Gas Plants
In January 2016, Enbridge announced the acquisition of the Tupper Main and Tupper West gas plants (the Tupper Plants) and associated pipelines from a Canadian subsidiary of Murphy Oil Corporation (Murphy Oil) for a purchase price of approximately $0.5 billion. The Tupper Plants have a combined total licensed capacity of 320 mmcf/d and are located within the Montney gas play, 35 kilometres southwest of Dawson Creek, British Columbia, adjacent to Enbridge's existing Sexsmith gathering system and close to the Alliance Pipeline which is 50% owned by the Fund Group. These assets, including 53 kilometres of high pressure pipelines, are currently in operation and are underpinned by long-term take-or-pay contracts. The purchase price will initially be funded from available sources of liquidity and the acquisition, subject to regulatory review and approval, is anticipated to close by the second quarter of 2016.

Aux Sable Extraction Plant Expansion
In 2014, the Company approved the expansion of fractionation capacity and related facilities at the Aux Sable extraction and fractionation plant located in Channahon, Illinois. The expansion will serve the growing NGL-rich gas stream on the Alliance Pipeline, allow for effective management of Alliance Pipeline's downstream natural gas heat content and support additional production and sale of NGL products. The expansion is expected to provide approximately 24,500 bpd of incremental fractionation capacity and is expected to be placed into service in the second quarter of 2016. The Company's share of the project cost is approximately US$0.1 billion.

Stampede Oil Pipeline
In January 2015, Enbridge announced that it will build, own and operate a crude oil pipeline in the Gulf of Mexico to connect the planned Stampede development, which is operated by Hess Corporation, to an existing third party pipeline system. The Stampede Pipeline, a 26-kilometre (16-mile), 18-inch diameter pipeline with capacity of approximately 100,000 bpd, will originate in Green Canyon Block 468, approximately 350 kilometres (220 miles) southwest of New Orleans, Louisiana, at an estimated depth of 1,200 metres (3,900 feet). Stampede Pipeline is expected to be completed at an approximate cost of US$0.2 billion and is expected to be placed into service in 2018.

Green Power and Transmission

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28 New Creek Wind Project

29 Rampion Offshore Wind Project

- Current Assets
- Wind Assets
- Wind Assets – The Fund Group[1]
- Solar Assets

1 Effective September 1, 2015, Enbridge transferred certain Canadian renewable energy assets to the Fund Group.For further details, refer to *Canadian Restructuring Plan.*

GREEN POWER AND TRANSMISSION

Keechi Wind Project

In 2014, Enbridge announced it had entered into an agreement with Renewable Energy Systems Americas Inc. (RES Americas) to own and operate the 110-MW Keechi, located in Jack County, Texas. The project was constructed by RES Americas under a fixed price, engineering, procurement and construction agreement at a total cost of approximately US$0.2 billion, and it entered service in January 2015. The electricity generated by Keechi is delivered into the Electric Reliability Council of Texas, Inc. market under a 20-year PPA with Microsoft Corporation.

New Creek Wind Project

In November 2015, Enbridge announced it had acquired a 100% interest in the 103-MW New Creek, located in Grant County, West Virginia, from EverPower Wind Holdings, LLC. Enbridge's total investment is expected to be approximately US$0.2 billion. New Creek will comprise 49 Gamesa turbines and is targeted to be in service in December 2016. The project will be constructed under a fixed-price engineering, procurement and construction agreement, with White Construction Inc. Gamesa will provide turbine operations and maintenance services under a five-year fixed price contract. The project is backed by renewable energy credit sales and medium and long-term offtake agreements.

Rampion Offshore Wind Project

In November 2015, Enbridge announced the acquisition of a 24.9% interest in the 400-MW Rampion Project in the United Kingdom, located 13 kilometres (8 miles) off the Sussex coast in the United Kingdom at its nearest point. The Company's total investment in the project through construction is expected to be approximately $0.8 billion (£0.37 billion). The Rampion Project was developed and is being constructed by E.ON Climate & Renewables UK Limited, a subsidiary of E.ON SE (E.ON). Construction of the wind farm began in September 2015 and it is expected to be fully operational in 2018. The Rampion Project is backed by revenues from the United Kingdom's fixed price Renewable Obligation certificates program and a 15-year PPA. Under the terms of the agreement, Enbridge became one of the three shareholders in Rampion Offshore Wind Limited which owns the Rampion Project with the United Kingdom's Green Investment Bank plc holding a 25% interest and E.ON retaining the balance of 50.1% interest. Enbridge has incurred costs to date of approximately $0.2 billion (£0.10 billion).

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by the Company, but have not yet met the Company's criteria to be classified as commercially secured. The project descriptions below reflect the status of the projects up to February 19, 2016, the date of the original filing of the Company's MD&A for the year ended December 31, 2015. For a current description of project updates since February 19, 2016, refer to the Company's MD&A for the three months ended March 31, 2016 filed on May 12, 2016.

The Company also has additional attractive projects under development that have not yet progressed to the point of public announcement.

LIQUIDS PIPELINES

Northern Gateway Project

Northern Gateway involves constructing a twin 1,178-kilometre (731-mile) pipeline system from near Edmonton, Alberta to a new marine terminal in Kitimat, British Columbia. One pipeline would transport crude oil for export from the Edmonton area to Kitimat and is proposed to be a 36-inch diameter line with an initial capacity of 525,000 bpd. The other pipeline would be used to transport imported condensate from Kitimat to the Edmonton area and is proposed to be a 20-inch diameter line with an initial capacity of 193,000 bpd.

In 2010, Northern Gateway submitted an application to the NEB and the Joint Review Panel (JRP) was established to review the proposed project, pursuant to the NEB Act and the Canadian Environmental Assessment Act. The JRP had a broad mandate to assess the potential environmental effects of the project and to determine if development of Northern Gateway was in the public interest.

In December 2013, the JRP issued its report on Northern Gateway. The report found that the petroleum industry is a significant driver of the Canadian economy and an important contributor to the Canadian standard of living and noted that the benefits of Northern Gateway outweigh its burdens and that "Canadians would be better off with the Enbridge Northern Gateway Project than without it." The Government of Canada consulted with Aboriginal groups on the JRP report and its recommendations prior to making its decision on whether to direct the NEB to issue the Certificates of Public Convenience and Necessity for the pipelines.

In June 2014, the Governor in Council approved Northern Gateway, subject to 209 conditions following the recommendation from the JRP. The Company continues to work closely with its customers in advancing this project to open West Coast market access and is making progress in fulfilling the conditions and building relationships and trust with communities and Aboriginal groups along the proposed route.

Nine applications to the Federal Court of Appeal (Federal Court) for leave for judicial review of the Order in Council were filed in July 2014. The applicants made two basic arguments in seeking leave. First, they argued that the JRP report and the Order in Council contain evidentiary gaps or gaps in reasoning. Second, they alleged that the Crown failed to discharge its constitutional duty to consult and, if appropriate, accommodate the Aboriginal applicants.

The Federal Court consolidated the nine applications into one proceeding. The hearing of these applications commenced in Vancouver, British Columbia, on October 1, 2015 and concluded on October 8, 2015. Depending on the outcome of these proceedings, which is anticipated for 2016, an application for Leave to Appeal to the Supreme Court of Canada is a possibility.

The Company reviewed an updated cost estimate of Northern Gateway based on full engineering analysis of the pipeline route and terminal location. Based on this comprehensive review, the Company expects that the final cost of the project will be substantially higher than the preliminary cost figures included in the Northern Gateway filing with the JRP, which reflected a preliminary estimate prepared in 2004 and escalated to 2010. The drivers behind this substantial increase include the significant costs associated with escalation of labour and construction costs, satisfying the 209 conditions imposed in the Governor in Council approval, a larger portion of high cost pipeline terrain, more extensive terminal site rock excavations and a delayed anticipated in-service date. The updated cost estimate is currently being assessed and refined by Northern Gateway and the potential shippers. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.6 billion, of which approximately half is being funded by potential shippers on Northern Gateway.

The in-service date of the project will be dependent upon the timing and outcome of judicial reviews, continued commercial support, receipt of regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities). Of the 48 Aboriginal groups eligible to participate as equity owners, 28 have signed up to do so.

Given the many uncertainties surrounding Northern Gateway, including final ownership structure, the potential financial impact of the project cannot be determined at this time.

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

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

LIQUIDS PIPELINES

EARNINGS BEFORE INTEREST AND INCOME TAXES

	2015	2014
(millions of Canadian dollars)		
Canadian Mainline	**896**	663
Lakehead System	**1,108**	836
Regional Oil Sands System	**341**	301
Mid-Continent and Gulf Coast	**516**	319
Southern Lights Pipeline	**155**	121
Bakken System	**213**	233
Feeder Pipelines and Other	**155**	119
Adjusted earnings before interest and income taxes	**3,384**	2,592
Canadian Mainline - changes in unrealized derivative fair value loss	**(1,390)**	(499)
Canadian Mainline - Line 9B costs incurred during reversal	**(3)**	(5)
Lakehead System - changes in unrealized derivative fair value gains/(loss)	**(10)**	8
Lakehead System - hydrostatic testing	**(72)**	-
Lakehead System - leak remediation costs	**-**	(97)
Regional Oil Sands System - make-up rights adjustment	**9**	8
Regional Oil Sands System - leak insurance recoveries	**32**	10
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs	**(6)**	(5)
Regional Oil Sands System - loss on disposal of non-core assets	**(9)**	-
Regional Oil Sands System - prior period adjustment	**21**	-
Mid-Continent and Gulf Coast - changes in unrealized derivative fair value gains/(loss)	**(7)**	4
Mid-Continent and Gulf Coast - make-up rights adjustment	**(54)**	(41)
Southern Lights Pipeline - changes in unrealized derivative fair value gains/(loss)	**(87)**	3
Bakken System - asset impairment loss	**(86)**	-
Bakken System - make-up rights adjustment	**8**	(3)
Bakken System - changes in unrealized derivative fair value gains/(loss)	**(5)**	4
Feeder Pipelines and Other - gain on sale of non-core assets	**91**	-
Feeder Pipelines and Other - make-up rights adjustment	**(6)**	5
Feeder Pipelines and Other - project development costs	**(3)**	(4)
Feeder Pipelines and Other - changes in unrealized derivative fair value loss	**(1)**	-
Earnings before interest and income taxes	**1,806**	1,980

Liquids Pipelines adjusted EBIT was $3,384 million in 2015 compared with adjusted EBIT of $2,592 million in 2014. The Company continued to realize growth on Canadian Mainline primarily due to higher throughput that resulted from strong oil sands production in western Canada combined with strong downstream refinery demand, as well as successful efforts by the Company to optimize capacity and throughput and to enhance scheduling efficiency with shippers. Higher throughput and contributions from new assets placed into service in 2015 and 2014 further bolstered higher year-over-year adjusted EBIT from the Lakehead System. The positive effects on Canadian Mainline were however partially offset by a lower year-over-year average Canadian Mainline IJT Residual Benchmark Toll. In 2015, Mid-Contintent and Gulf Coast benefitted from the full-year operation of Flanagan South and Seaway Pipeline Twin, which commenced in late 2014.

Additional details on items impacting Liquids Pipelines EBIT include:

- Canadian Mainline loss before interest and income taxes for 2015 and EBIT for 2014 reflected changes in unrealized fair value losses on derivative financial instruments used to manage risk exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Canadian Mainline loss before interest and income taxes for 2015 and EBIT 2014 included depreciation and interest expenses charged to Line 9B while it was idled and undergoing a reversal as part of the Company's Eastern Access initiative.
- Lakehead System EBIT for 2015 included charges for hydrostatic testing performed on Line 2B.
- Lakehead System EBIT for 2014 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. Refer to *Liquids Pipelines – Lakehead System – Lakehead System Lines 6A and 6B Crude Oil Releases – Line 6B Crude Oil Release.*
- Regional Oil Sands System EBIT for 2015 and 2014 included make-up rights adjustments to recognize revenue for certain long-term take-or-pay contracts rateably over the contract life. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. Generally, under such take-or-pay contracts, payments are received rateably over the life of the contract as capacity is provided, regardless of volumes shipped, and are non-refundable. Should make-up rights be utilized in future periods, costs associated with such transportation service are typically passed through to shippers, such that little or no cost is borne by Enbridge. For the purposes of adjusted EBIT, the Company reflects contributions from these contracts rateably over the life of the contract, consistent with contractual cash payments under the contract.
- Regional Oil Sands System EBIT for 2015 and 2014 included insurance recoveries associated with the Line 37 crude oil release, which occurred in June 2013. Refer to *Liquids Pipelines – Regional Oil Sands System – Line 37 Crude Oil Release*.
- Regional Oil Sands System EBIT for each period included charges, before insurance recoveries, related to the Line 37 crude oil release, which occurred in June 2013. Refer to *Liquids Pipelines – Regional Oil Sands System – Line 37 Crude Oil Release*.
- Southern Lights Pipeline EBIT for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to manage foreign exchange risk exposure on United States dollar cash flows from the Southern Lights Class A units.
- Bakken System EBIT for 2015 reflected an asset impairment charge related to EEP's Berthold rail facility due to contracts that have not been renewed beyond 2016.
- Feeder Pipelines and Other EBIT for 2015 and 2014 included certain business development costs related to Northern Gateway that are anticipated to be recovered over the life of the project.

CANADIAN MAINLINE

The mainline system is comprised of the Canadian Mainline and the Lakehead System. The Canadian Mainline is a common carrier pipeline system which transports various grades of oil and other liquid hydrocarbons within western Canada and from western Canada to the Canada/United States border near Gretna, Manitoba and Neche, North Dakota and from the United States/Canada border near Port Huron, Michigan and Sarnia, Ontario to eastern Canada and the northeastern United States. The Canadian Mainline includes six adjacent pipelines, with a combined design operating capacity of approximately 2.85 million bpd that connect with the Lakehead System at the Canada/United States border, as well as four crude oil pipelines and one refined products pipeline that deliver into eastern Canada and the northeastern United States. It also includes certain related pipelines and infrastructure, including decommissioned and deactivated pipelines. Enbridge has operated, and frequently expanded, the Canadian Mainline since 1949. Effective September 1, 2015, the closing date of the Canadian Restructuring Plan, Enbridge transferred the Canadian Mainline to the Fund Group – see *Canadian Restructuring Plan.* The Lakehead System is the portion of the mainline system in the United States that continues to be managed by Enbridge through its subsidiaries, EEP and EELP – see *Liquids Pipelines – Lakehead System.*

Competitive Toll Settlement

The CTS is the current framework governing tolls paid for products shipped on the Canadian Mainline, with the exception of Lines 8 and 9 which are tolled on a separate basis. The 10-year settlement was negotiated by representatives of Enbridge, the Canadian Association of Petroleum Producers and shippers on the Canadian Mainline. It was approved by the NEB on June 24, 2011 and took effect on July 1, 2011. The CTS provides for a Canadian Local Toll (CLT) for deliveries within western Canada, which is based on the 2011 Incentive Tolling Settlement toll, as well as an IJT for crude oil shipments originating in western Canada on the Canadian Mainline and delivered into the United States, via the Lakehead System, and into eastern Canada. These tolls are denominated in United States dollars. The IJT is designed to provide shippers on the mainline system with a stable and competitive long-term toll, thereby preserving and enhancing throughput on both the Canadian Mainline and the Lakehead System. The IJT and the CLT were both established at the time of implementation of the CTS and are adjusted annually, on July 1 of each year, at a rate equal to 75% of the Canada Gross Domestic Product at Market Price Index published by Statistics Canada. Certain events may trigger a renegotiation of the CTS by Enbridge or the shippers. These include (i) a regulatory change that results in cumulative capital expenditures for integrity work on the Canadian Mainline increasing by more than $100 million, or (ii) if the nine month average volume on the Canadian Mainline, ex-Gretna, Manitoba, falls below the minimum threshold volume (currently 1.35 million bpd). If a renegotiation of the CTS is triggered, Enbridge and the shippers will meet and use reasonable efforts to agree on how the CTS can be amended to accommodate the event. If Enbridge and the shippers are unable to agree on the manner in which the CTS is to be amended, then, absent an extension to the renegotiation period, the CTS will terminate and Enbridge will need to file a new toll application for the Canadian Mainline. Two years prior to the end of the term of the CTS, Enbridge and the shippers will establish a group for the purposes of negotiating a new settlement to replace the CTS once it expires.

Although the CTS has a 10 year term, it does not require shippers to commit to certain volumes. Shippers nominate volumes on a monthly basis and Enbridge allocates capacity to maximize the efficiency of the Canadian Mainline.

Local tolls for service on the Lakehead System are not affected by the CTS and continue to be established pursuant to the Lakehead System’s existing toll agreements, as described under *Lakehead System* below. Under the terms of the IJT agreement between Enbridge and EEP, the Canadian Mainline’s share of the IJT toll relating to pipeline transportation of a batch from any western Canada receipt point to the United States border is equal to the IJT toll applicable to that batch’s United States delivery point less the Lakehead System’s local toll to that delivery point. This amount is referred to as the Canadian Mainline IJT Residual Benchmark Toll and is denominated in United States dollars.

Results of Operations

Canadian Mainline adjusted EBIT was $896 million for the year ended December 31, 2015 compared with $663 million for the year ended December 31, 2014. The year-over-year increase reflected higher throughput from strong oil sands production combined with strong refinery demand in the midwest market partly due to a start-up of a midwest refinery’s conversion to heavy oil processing in the second quarter of 2014. Higher throughput in the second half of 2015 was also achieved from the expansion of the Company’s mainline system completed in July 2015 and through continued efforts by the Company to optimize capacity utilization and to enhance scheduling efficiency with shippers. Although throughput increased relative to the comparative periods in 2014, further throughput growth in 2015 was hindered by upstream plant maintenance in Alberta during the second and third quarters which impacted light volumes, and an unplanned shutdown of a midwest refinery that impacted the takeaway of heavy volumes in the third quarter. These negative impacts on throughput were alleviated towards the latter part of the fourth quarter of 2015. Other factors contributing to an increase in adjusted EBIT were higher terminalling revenues and the impact of a stronger United States dollar as the IJT Benchmark Toll and its components are set in United States dollars. The majority of the Company’s foreign exchange risk on Canadian Mainline revenues is hedged. For the year ended December 31, 2015, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.102, compared with $1.016 for the corresponding 2015 period. In addition, Canadian Mainline fourth quarter of 2015 adjusted EBIT also reflected one month of revenues from Line 9B which was placed into service in December 2015.

Partially offsetting the positive factors noted above was a lower year-over-year average Canadian Mainline IJT Residual Benchmark Toll, although this impact lessened commencing the second quarter of 2015 as effective April 1, 2015, this toll increased by US$0.10 per barrel to US$1.63 per barrel. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher due to the recovery of incremental costs associated with EEP's growth projects. Also mitigating the impact of a lower Canadian Mainline IJT Residual Benchmark Toll were new surcharges related to system expansions, including a surcharge for the Edmonton to Hardisty Expansion pipeline completed in April 2015. Other factors which negatively impacted adjusted EBIT were higher power costs associated with higher throughput and higher depreciation expense due to an increased asset base.

In 2015, the Company also commenced collecting, in its tolls, NEB mandated future abandonment costs from shippers. For the year ended December 31, 2015, approximately $38 million in revenue was recorded, but this amount was offset by a regulatory expense within operating and administrative expense. For further details, refer to *Critical Accounting Estimates.*

Supplemental information related to the Canadian Mainline for the years ended December 31, 2015 and 2014 is provided below.

December 31,	**2015**	2014
(United States dollars per barrel)		
IJT Benchmark Toll[1]	**$4.07**	$4.02
Lakehead System Local Toll[2]	**$2.44**	$2.49
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.63**	$1.53

1 *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, 2014, the IJT Benchmark Toll increased from US$3.98 to US$4.02 and increased to US$4.07 effective July 1, 2015.*

2 *The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective January 1, 2014, the Lakehead System Local Toll decreased from US$2.18 to US$2.17. In 2014, EEP delayed its annual April 1 tariff filing for its Lakehead System as it was in negotiations with the Canadian Association of Petroleum Producers concerning certain components of the tariff rate structure. The toll application was filed with the United States Federal Energy Regulatory Commission (FERC) on June 27, 2014, and effective August 1, 2014, the Lakehead System Local Toll increased from US$2.17 to US$2.49. Effective April 1, 2015, the Lakehead System Local Toll decreased from US$2.49 to US$2.39. Effective July 1, 2015, this toll increased to US$2.44. Effective April 1, 2016, this toll increased to US$2.61.*

3 *The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. For any shipment, this toll is the difference between the IJT Benchmark Toll and the Lakehead System Local Toll. Effective January 1, 2014, this toll increased from US$1.80 to US$1.81. This toll increased to US$1.85 effective July 1, 2014 and subsequently decreased to US$1.53 effective August 1, 2014, coinciding with the revised Lakehead System Local Toll. Effective April 1, 2015, the Canadian Mainline IJT Residual Benchmark Toll increased to US$1.63. Effective April 1, 2016, this toll decreased to US$1.46, coinciding with the revised Lakehead System Local Toll.*

Throughput Volume[1]

	Q1	Q2	Q3	Q4	Full Year
2015	**2,210**	**2,073**	**2,212**	**2,243**	**2,185**
2014	1,904	1,968	2,039	2,066	1,995

1 *Throughput, presented in thousands of bpd, 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. Lines 8 and 9 are currently tolled on a separate basis and comprise a relatively small proportion of total Canadian Mainline revenues. Line 9B was idled in late 2013 for reversal and expansion. The project was completed and the 300,000 bpd line was placed into service in December 2015 as part of the Company's Eastern Access initiative – see *Growth Projects –*

Commercially Secured Projects – Liquids Pipelines – Eastern Access – Eastern Access (the Fund Group). 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, Manitoba 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 CLT applies. Despite the many factors that 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 expense 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.

Power, the most significant variable operating cost, is subject to variations in operating conditions, including system configuration, pumping patterns and pressure requirements; however, the primary determinants of this cost are the 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 additions to property, plant and equipment due to new facilities, including integrity capital expenditures.

LAKEHEAD SYSTEM

The Lakehead System consists of the United States portion of the mainline system that is managed by Enbridge through its subsidiaries, EEP and EELP. For an overview of the mainline system, refer to *Liquids Pipelines – Canadian Mainline*.

Tariffs and Transportation Rates

Transportation rates are governed by the FERC for deliveries from the Canada-United States border near Neche, North Dakota and from Clearbrook, Minnesota to certain principal delivery points. The Lakehead System periodically adjusts these transportation rates as allowed under the FERC's index methodology and tariff agreements, the main components of which are base rates and Facilities Surcharge Mechanism. Base rates, the base portion of the transportation rates for the Lakehead System, are subject to an annual adjustment which cannot exceed established ceiling rates as approved by the FERC. The Facilities Surcharge Mechanism allows the Lakehead System to recover costs associated with certain shipper-requested projects through an incremental surcharge in addition to the existing base rates, and is subject to annual adjustment.

Throughput Volume[1]

	Q1	Q2	Q3	Q4	Full Year
2015	**2,330**	**2,208**	**2,338**	**2,388**	**2,315**
2014	2,000	2,088	2,172	2,187	2,113

1 Throughput, presented in thousands of bpd, represents mainline system deliveries to the United States mid-west and eastern Canada.

Results of Operations

Lakehead System adjusted EBIT was $1,108 million for the year ended December 31, 2015 compared with $836 million for the year ended December 31, 2014. The year-over-year increase in adjusted EBIT reflected stronger operating performance, as well as the favourable effect of translating United States dollar earnings to Canadian dollars at a higher average United States to Canadian dollar exchange rate (Exchange Rate) in 2015 compared with 2014.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$868 million for the year ended December 31, 2015 compared with US$756 million for the year ended December 31, 2014. The year-over-year increase reflected higher throughput and tolls, as well as contributions from new assets placed into service in 2014 and 2015, the most prominent being the expansion of the Company's mainline system completed in July 2015 and the replacement and expansion of Line 6B completed in 2014. Partially offsetting the increase in adjusted EBIT were higher operating and administrative costs, incremental power costs associated with higher throughput and higher depreciation expense from an increased asset base.

As noted above, positively impacting year-over-year adjusted EBIT was the favourable impact of translating United States dollar earnings at a higher Exchange Rate in 2015 due to the strengthening United States dollar versus the Canadian dollar. The Exchange Rate was $1.28 for the year ended December 31, 2015 compared with $1.10 for the comparative period of 2014. A portion of Lakehead System United States dollar EBIT is hedged as part of the Company's enterprise-wide financial risk management program. The Company uses foreign exchange derivative instruments to manage the foreign exchange risk arising from its United States businesses including the Lakehead System and realized gains and losses from these derivative instruments are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

Lakehead System - Alberta Clipper Drop Down

On January 2, 2015, Enbridge completed the transfer of its 66.7% interest in the United States segment of the Alberta Clipper Pipeline, held through a wholly-owned Enbridge subsidiary in the United States, to EEP. At the time of the transfer, EEP already owned the remaining 33.3% interest in the United States segment of Alberta Clipper. Aggregate consideration for the transfer was US$1 billion, consisting of approximately US$694 million of Class E equity units issued to Enbridge by EEP and the repayment of approximately US$306 million of indebtedness owed to Enbridge. The terms of the transfer were reviewed and recommended by an independent committee of EEP.

The Class E units issued to Enbridge are entitled to the same distributions as the Class A common units held by the public and are convertible into Class A common units on a one-for-one basis at Enbridge's option. However, the Class E units are not entitled to distributions with respect to the quarter ended December 31, 2014. The Class E units are redeemable at EEP's option after 30 years, if not converted earlier by Enbridge. The units have a liquidation preference equal to their notional value at December 23, 2014 of US$38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of EEP's Class A common units.

The aggregate consideration of US$1 billion corresponded to an approximate 10.7 times multiple of then expected 2015 Alberta Clipper Earnings before interest, tax, depreciation and amortization (EBITDA). If after two years, the cumulative adjusted EBITDA of the Alberta Clipper Pipeline for fiscal years 2015 and 2016 is more than five percent below the EBITDA projections for those years, a number of Class E units representing US$50 million of value will be cancelled by EEP effective as of June 15, 2017 for no consideration.

The United States segment of the Alberta Clipper Pipeline is a 523-kilometre (325-mile), 36-inch diameter crude oil pipeline from the United States border near Neche, North Dakota to Superior, Wisconsin. The initial capacity of the line was 450,000 bpd and was constructed under the terms of a joint funding agreement under which Enbridge funded two-thirds of the capital costs in return for a corresponding economic interest in the earnings and cash flow from the investment. In 2015, the line was expanded in two phases to a capacity of 800,000 bpd through the addition of increased pumping horsepower; however, EEP is awaiting an amendment to the current Presidential border crossing permit to allow for operation of Alberta Clipper Pipeline at its currently planned operating capacity of 800,000 bpd. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining this amendment. The required expansion investments are subject to separate joint funding arrangements between Enbridge and EEP and were not included as part of the above noted drop down transaction. Refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Lakehead System Mainline Expansion (EEP)*.

Lakehead System Lines 6A and 6B Crude Oil Releases

The Lakehead System Lines 6A and 6B Crude Oil Releases narratives below reflect the status of these crude oil releases up to February 19, 2016, the date of the original filing of the Company's MD&A for the year ended December 31, 2015. For a current description of updates related to these crude oil releases since February 19, 2016, refer to the Company's MD&A for the three months ended March 31, 2016 filed on May 12, 2016.

Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Kalamazoo River via Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan.

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the EPA (the EPA Order) which required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. In February 2015, the EPA acknowledged EEP's completion of the EPA Order. In November 2014, regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). The MDEQ has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

In May 2015, EEP reached a settlement with the MDEQ and the Michigan Attorney General's offices regarding the Line 6B crude oil release. As stipulated in the settlement, EEP agrees to: (1) provide at least 300 acres of wetland through restoration, creation, or banked wetland credits, to remain as wetland in perpetuity; (2) pay US$5 million as mitigation for impacts to the banks, bottomlands, and flow of Talmadge Creek and the Kalamazoo River for the purpose of enhancing the Kalamazoo River watershed and restoring stream flows in the River; (3) continue to reimburse the State of Michigan for costs arising from oversight of EEP activities since the release; and (4) continue monitoring, restoration and invasive species control within state-regulated wetlands affected by the release and associated response activities. The timing of these activities is based upon the work plans approved by the State of Michigan.

As at December 31, 2015, EEP's total cost estimate for the Line 6B crude oil release was US$1.2 billion ($193 million after-tax attributable to Enbridge), which is unchanged since December 31, 2014. As at December 31, 2014, the total cost estimate for the Line 6B crude oil release increased by US$86 million as compared to December 31, 2013. The total cost increase of US$86 million during the year ended December 31, 2014, was primarily related to the MDEQ approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake and estimated civil penalties under the Clean Water Act of the United States (Clean Water Act), as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 2015. 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
A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

EEP has completed the cleanup, remediation and restoration of the areas affected by the release. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

The total estimated cost for the Line 6A crude oil release was approximately US$51 million ($7 million after-tax attributable to Enbridge) before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. As at December 31, 2015, EEP has no remaining estimated liability.

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability for Enbridge and its affiliates. Including EEP's remediation spending through December 31, 2015, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at December 31, 2015, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurers of US$145 million of coverage, as one particular insurer is disputing the recovery eligibility for costs related to EEP's claim on the Line 6B crude oil release and the other remaining insurers assert that their payment is predicated on the outcome of the recovery from that insurer. EEP received a partial recovery payment of US$42 million from the other remaining insurers and amended its lawsuit such that it now includes only one insurer.

Of the remaining US$103 million coverage limit, US$85 million is the subject matter of a lawsuit against one particular insurer. In March 2015, Enbridge reached an agreement with that insurer to submit the US$85 million claim to binding arbitration. The recovery of the remaining US$18 million is awaiting resolution of that arbitration, which is not scheduled to occur until the fourth quarter of 2016. While EEP believes those costs are eligible for recovery, there can be no assurance that EEP will prevail in the arbitration.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2016 with a liability program aggregate limit of US$860 million, which includes sudden and accidental pollution liability. In the unlikely event multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings
A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Five actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release. Based on the current status of these cases, the Company does not expect the outcome of these actions to be material to its results of operations or financial condition.

As at December 31, 2015, included in EEP's estimated costs related to the Line 6B crude oil release is US$44 million in fines and penalties. Of this amount, US$40 million relates to civil penalties under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$40 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures, when combined with any fine or penalty, could be material. EEP has entered into a tolling agreement with the applicable governmental agencies and discussions with these governmental agencies regarding fines, penalties and injunctive relief are ongoing.

In June 2015, Enbridge reached a separate agreement with the United States (Federal Natural Resources Damages Trustees), State of Michigan (State Natural Resources Damages Trustees), Match-E-Be-Nash-She-Wish Band of the Potawatomi Indians, and the Nottawaseppi Huron Band of the Potawatomi Indians, and paid approximately US$4 million that was accrued to cover a variety of projects, including the restoration of 175 acres of oak savanna in the Fort Custer State Recreation Area and wild rice beds along the Kalamazoo River.

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 the Illinois state court in connection with this crude oil release. On February 20, 2015, EEP agreed to a consent order releasing it from any claims, liability, or penalties.

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 1,700 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. 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. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA again considered the status of the pipeline in light of information they acquired throughout 2014. On December 9, 2014, EEP received a letter from the PHMSA approving its request to continue the normal operation of Line 14 without pressure restrictions. EEP has no remaining estimated liability for this release.

REGIONAL OIL SANDS SYSTEM
Regional Oil Sands System includes three long haul pipelines, the Athabasca Pipeline, Waupisoo Pipeline and Woodland Pipeline and two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located 70 kilometres (45 miles) south of Fort McMurray where the Waupisoo Pipeline initiates. Regional Oil Sands System also includes the Wood Buffalo Pipeline and Norealis Pipeline, each of which provides access for oil sands production from near Fort McMurray to the Cheecham Terminal. The recently completed Woodland Pipeline extension project further extended the Woodland Pipeline south from the Company's Cheecham Terminal to its Edmonton Terminal. Regional Oil Sands System also includes a variety of other facilities such as the MacKay River, Christina Lake, Surmont, Long Lake and AOC laterals and related facilities. Regional Oil Sands System

currently serves eight producing oil sands projects. Effective September 1, 2015, the closing date of the Canadian Restructuring Plan, Enbridge transferred the Regional Oil Sands System to the Fund Group – see *Canadian Restructuring Plan.*

The Athabasca Pipeline is a 540-kilometre (335-mile) synthetic and heavy oil pipeline. Built in 1999, it links the Athabasca oil sands in the Fort McMurray region to the major Alberta pipeline hub at Hardisty, Alberta. The Athabasca Pipeline's capacity is 570,000 bpd after completion of a pipeline expansion in December 2013. The Company has long-term take-or-pay and non take-or-pay agreements with multiple shippers on the Athabasca Pipeline. Revenues are recorded based on the contract terms negotiated with the major shippers, rather than the cash tolls collected.

The Waupisoo Pipeline is a 380-kilometre (236-mile) synthetic and heavy oil pipeline that entered service in 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline originates at the Cheecham Terminal and terminates at the major Alberta pipeline hub at Edmonton. The pipeline has a capacity of 550,000 bpd, depending on crude slate. The Company has long-term take-or-pay commitments with multiple shippers on the Waupisoo Pipeline who have collectively contracted for 80% to 90% of the capacity, subject to some short-term variability dependent on the timing of when certain shippers' commitments expire and commence.

Results of Operations

Regional Oil Sands System adjusted EBIT for the year ended December 31, 2015 was $341 million compared with $301 million for the year ended December 31, 2014. Higher adjusted EBIT primarily reflected contributions from assets placed into service in 2014 and 2015, including the Sunday Creek Terminal and Woodland Pipeline Extension projects that were placed into service in the third quarter of 2015, Surmont Phase 2 Expansion project that was placed into service in phases in November 2014 and March 2015, as well as Norealis Pipeline which was completed in April 2014. These positive impacts were partially offset by higher depreciation expense from a larger asset base, as well as a reduction in contracted volumes on the Athabasca Mainline, mitigated in part by higher uncommitted volumes on this pipeline.

Line 37 Crude Oil Release

On June 22, 2013, Enbridge reported a release of light synthetic crude oil on its Line 37 pipeline approximately two kilometres north of Enbridge's Cheecham Terminal. Line 37 connects facilities in the Long Lake area to the Cheecham Terminal. The Company estimated the volume of the release at approximately 1,300 barrels, caused by unusually high water levels in the region that triggered ground movement on the right-of-way. The oil released from Line 37 was recovered and on July 11, 2013, Line 37 returned to service at reduced operating pressure. Normal operating pressure was restored on Line 37 on July 29, 2013 after finalization of geotechnical analysis.

As a precaution, on June 22, 2013, the Company shut down the pipelines that share a corridor with Line 37, including the Athabasca, Waupisoo, Wood Buffalo and Woodland pipelines. Following extensive engineering and geotechnical analysis, all of the lines except Woodland Pipeline were returned to service by July 19, 2013. The Woodland Pipeline had been in the process of line-fill at the time of the shutdown; line-fill activities were completed in the third quarter of 2013.

For the years ended December 31, 2015 and 2014, the Company's EBIT reflected remediation and long-term stabilization costs of approximately $6 million and $5 million before insurance recoveries, respectively. Lost revenues associated with the shutdown of Line 37 and the pipelines sharing a corridor with Line 37 were minimal. At the time of the Line 37 crude oil release, Enbridge carried liability insurance for sudden and accidental pollution events, subject to a $10 million deductible.

The integrity and stability costs associated with remediating the impact of the high water levels were precautionary in nature and not covered by insurance. Enbridge expects to record receivables for amounts claimed for recovery pursuant to its insurance policies during the period that it deems realization of the claim for recovery to be probable. For the years ended December 31, 2015 and 2014, Enbridge recognized insurance recoveries of $32 million and $10 million, respectively. On February 1, 2016, Enbridge was notified that the provincial government agency had completed and closed its investigation on this matter.

MID-CONTINENT AND GULF COAST

Mid-Continent and Gulf Coast includes Seaway and Flanagan South Pipelines, Spearhead Pipeline, as well as the Mid-Continent System that is managed by Enbridge through its subsidiary, EEP.

Seaway Pipeline

In 2011, Enbridge acquired a 50% interest in the 1,078-kilometre (670-mile) Seaway Pipeline, including the 805-kilometre (500-mile), 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas, as well as the Texas City Terminal and Distribution System which serves refineries in the Houston and Texas City areas. Seaway Pipeline also includes 6.8 million barrels of crude oil tankage on the Texas Gulf Coast.

The flow direction of Seaway Pipeline was reversed in May 2012, enabling it to transport crude from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. Further pump station additions and modifications were completed in January 2013, increasing capacity available to shippers from an initial 150,000 bpd to up to approximately 400,000 bpd, depending on crude oil slate. In late 2014, a second line was placed into service to more than double the existing capacity to 850,000 bpd. Seaway Pipeline also includes a 161-kilometre (100-mile) pipeline from the ECHO crude oil terminal in Houston, Texas to the Port Arthur/Beaumont, Texas refining centre.

Flanagan South Pipeline

Flanagan South is a 950-kilometre (590-mile), 36-inch diameter interstate crude oil pipeline that originates at the Company’s terminal at Flanagan, Illinois and terminates in Cushing, Oklahoma. Flanagan South and associated pumping stations were completed in the fourth quarter of 2014 and the majority of the pipeline parallels Spearhead Pipeline’s right-of-way. Flanagan South has an initial design capacity of approximately 600,000 bpd; however, in its initial years, it is not expected to operate at its full design capacity.

Spearhead Pipeline

Spearhead Pipeline is a long-haul pipeline that delivers crude oil from Flanagan, Illinois, a delivery point on the Lakehead System to Cushing, Oklahoma. The pipeline was originally placed into service in March 2006 and an expansion was completed in May 2009, increasing capacity from 125,000 bpd to 193,300 bpd. Initial committed shippers and expansion shippers currently account for more than 70% of the 193,300 bpd capacity on Spearhead Pipeline. Both the initial committed shippers and expansion shippers were required to enter into 10-year shipping commitments at negotiated rates that were offered during the open season process. In March 2015, the commitment agreements with the initial committed shippers were extended for an additional 10 years. The balance of the capacity is currently available to uncommitted shippers on a spot basis at FERC approved rates.

Mid-Continent System

The Mid-Continent System is comprised of the Ozark Pipeline and storage terminals at Cushing, Oklahoma and Flanagan, Illinois. The Ozark Pipeline transports crude oil from Cushing, Oklahoma to Wood River, Illinois, where it delivers to a third-party refinery and interconnects with other third-party pipelines. The storage terminals consist of 100 individual storage tanks ranging in size from 78,000 to 575,000 barrels. Of the approximately 23.6 million barrels of storage shell capacity on the Mid-Continent System, the Cushing terminal accounts for approximately 20.1 million barrels. A portion of the storage facilities is used for operational purposes, while the remainder of the facilities is contracted with various crude oil market participants for their term storage requirements.

Results of Operations

Mid-Continent and Gulf Coast adjusted EBIT for the year ended December 31, 2015 was $516 million compared with adjusted EBIT of $319 million for the year ended December 31, 2014. The year-over-year increase in adjusted EBIT reflected stronger operating performance, as well as the favourable effect of translating United States dollar earnings to Canadian dollars at a higher Exchange Rate in 2015 compared with 2014.

Excluding the impact of foreign exchange translation to Canadian dollars, Mid-Continent and Gulf Coast adjusted EBIT was US$400 million for the year ended December 31, 2015 compared with US$287 for the year ended December 31, 2014. The increase in adjusted EBIT primarily reflected the effects of Flanagan South and Seaway Pipeline Twin commencing operations in late 2014. During the first half of 2015, as a result of Canadian Mainline apportionment, throughput on Seaway Pipeline and Flanagan South was lower than the throughput committed on these pipelines. However, this upstream apportionment was partially alleviated in the second half of 2015 through the expansion of the Company's mainline system completed in July 2015. When committed shippers on Flanagan South are unable to fulfill their volume commitments due to apportionment, they are provided with temporary relief to make up those volumes during the course of their contracts or the apportioned volumes are added onto the end of the contract term.

As noted above, positively impacting year-over-year adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in 2015 due to the strengthening United States dollar versus the Canadian dollar. Similar to Lakehead System, a portion of Mid-Continent and Gulf Coast United States dollar EBIT is hedged as part of the Company's enterprise-wide financial risk management program and realized gains and losses from the derivative instruments used to hedge foreign exchange risk arising from the Company's investment in United States businesses are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

Seaway Pipeline Regulatory Matters
Seaway Pipeline filed an application for market-based rates in December 2011. In relation to the original market-based rate application, FERC issued its decision rejecting Seaway Pipeline's application for market-based rates in February 2014. In the Seaway Pipeline order, FERC also announced a new methodology for determining whether a pipeline has market power and invited Seaway Pipeline to refile its market-based rate application consistent with the new policy. In December 2014, Seaway Pipeline filed a new market-based rate application. The FERC noticed the application in the Federal Register and in response several parties filed comments in opposition alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. On September 17, 2015, the FERC issued its decision setting the application for hearing. The case has been assigned to an ALJ, who held a scheduling conference on October 1, 2015, subsequent to which evidence was filed on December 3, 2015. The oral hearing with respect to the application will start on July 7, 2016. The ALJ will then issue its initial decision on the application by December 1, 2016. The ALJ's initial decision will then be considered by the FERC Commissioners, who can accept or reject the initial decision in full or in part. It is unclear when the FERC Commissioners' decision with respect to market based rates will be received as there is no timing requirement applicable to it.

Since the FERC had not issued a ruling on the market-based rate application, Seaway Pipeline filed for initial rates in order to have rates in effect by the in-service date. The uncommitted rate on Seaway Pipeline was challenged by several shippers. In September 2013, a decision from an ALJ was released finding that the committed and uncommitted rates on Seaway Pipeline should be reduced to reflect the ALJ's findings on the various cost of service inputs. Seaway Pipeline filed a brief with the FERC on October 15, 2013, challenging the ALJ's decision and asking for expedited ruling by the FERC on the committed rates. In February 2014, the FERC issued its decision upholding its policy to honour contracts and ordered the ALJ to revise her decision accordingly.

On May 9, 2014, the ALJ issued an initial decision on remand reiterating her previous findings and did not change her decision. Briefings have concluded and the full record was sent to the FERC for its final decision, which was issued February 1, 2016. In its order, FERC again upheld Seaway Pipeline's current committed rates structure and reversed the ALJ's holding that the committed rates should be reduced to cost-based levels. With respect to the uncommitted rates, the FERC permitted Seaway Pipeline to include the full Enbridge purchase price (including goodwill) in rate base. FERC's other cost-of-service rulings regarding the uncommitted rates were also largely favourable to Seaway Pipeline. A compliance filing calculating revised rates was filed on March 17, 2016.

SOUTHERN LIGHTS PIPELINE

Southern Lights Pipeline is a fully-contracted single stream pipeline that ships diluent from the Manhattan Terminal near Chicago, Illinois to three western Canadian delivery facilities, located at the Edmonton and Hardisty terminals in Alberta and the Kerrobert terminal in Saskatchewan. This 180,000 bpd 16/18/20-inch diameter pipeline was placed into service on July 1, 2010. Prior to the close of the Canadian Restructuring Plan, Southern Lights Canada was owned by SL Canada, an Alberta limited partnership. Southern Lights US is owned by Enbridge Pipelines (Southern Lights) L.L.C., a Delaware limited liability company. Both Southern Lights Canada and Southern Lights US receive tariff revenues under long-term contracts with committed shippers. Tariffs provide for recovery of all operating and debt financing costs plus an ROE of 10%. The Southern Lights Pipeline has assigned 10% of the capacity (18,000 bpd) for shippers to ship uncommitted volumes.

As part of Enbridge's sponsored vehicle strategy, on November 7, 2014, the Fund Group subscribed for and purchased Southern Lights Class A units which provide a defined cash flow stream to the Fund Group and represent the equity cash flows derived from the core rate base of Southern Lights Pipeline until June 30, 2040 – see *The Fund Group 2014 Drop Down Transaction*. Enbridge has guaranteed payment of the quarterly distributions that the Fund Group receives, except in circumstances of force majeure, certain regulatory actions and shipper defaults that remain unrecovered under the shipper contracts. The Fund Group has options to negotiate extensions for two additional 10-year terms beyond 2040 and to participate in equity returns from future expansions of Southern Lights Pipeline.

In addition, as part of the Canadian Restructuring Plan, effective September 1, 2015, Enbridge transferred all Class B units of Southern Lights Canada to the Fund Group. Following the closing of the Transaction, the Fund Group holds all the ownership, economic interests and voting rights, direct and indirect, in Southern Lights Canada. Enbridge continues to indirectly own all of the Class B Units of Southern Lights US.

Results of Operations

Southern Lights Pipeline adjusted EBIT for the year ended December 31, 2015 was $155 million compared with $121 million for the year ended December 31, 2014. The increase in year-over-year adjusted EBIT reflected higher recovery of negotiated depreciation rates in 2015 transportation tolls. Also positively impacting adjusted EBIT was the favourable impact of translating United States dollar earnings at a higher Exchange Rate in 2015 on the United States component of Southern Lights Pipelines.

BAKKEN SYSTEM

The Bakken System includes Canadian and United States operations. The United States portion of the Bakken System is comprised of a crude oil gathering and interstate pipeline transportation system servicing the Williston Basin in North Dakota and Montana, which includes the Bakken and Three Forks formation. The gathering pipelines collect crude oil from nearly 100 different receipt facilities located throughout western North Dakota and eastern Montana, including nearly 20 third-party gathering pipeline connections, with delivery to a variety of interconnecting pipeline and rail export facilities. The Canadian portion of the Bakken System connects into the United States portion in North Dakota as well as Enbridge's mainline terminal near Cromer, Manitoba.

Tolls and Tariffs

Tariffs on the United States portion of the Bakken System are governed by FERC and include a local tariff. Tolls on the Canadian portion of the Bakken System are regulated by the NEB and are based on long-term take-or-pay agreements with anchor shippers.

Results of Operations

Bakken System adjusted EBIT for the year ended December 31, 2015 was $213 million compared with $233 million for the year ended December 31, 2014. The Bakken System's operations include a Canadian and United States component. Within Bakken System adjusted EBIT for the year ended

December 31, 2015 was US$155 million compared with US$198 million for the corresponding 2014 period from its United States' operations.

Excluding the impact of foreign exchange translation to Canadian dollars, the decrease in year-over-year adjusted EBIT was primarily attributed to the United States portion of the Bakken System which experienced lower surcharge revenues as certain surcharge rates subject to an annual adjustment were decreased effective April 1, 2015, as well as higher power costs related to higher throughput on the system. The increase in throughput year-over-year partially offset the year-over-year adjusted EBIT decrease and was attributed to the system's enhanced market access and volumes shifting onto the system from other higher cost alternatives such as transportation by rail.

In 2015, the United States portion of the Bakken System earnings were translated at a higher Exchange Rate due to the strengthening United States dollar compared with the Canadian dollar. Similar to Lakehead System, a part of the United States' portion of the Bakken System United States dollar EBIT is hedged as part of the Company's enterprise-wide financial risk management program and realized gains and losses from the derivative instruments used to hedge foreign exchange risk arising from the Company's investment in United States businesses are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other primarily includes the Company's 85% interest in Olympic Pipe Line Company (Olympic), the largest refined products pipeline in the State of Washington, transporting approximately 290,000 bpd of gasoline, diesel and jet fuel. It also includes the NW System, which transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta, interests in a number of liquids pipelines in the United States, including the recently completed Southern Access Extension, the Toledo Pipeline, which connects with the EEP mainline at Stockbridge, Michigan, and the Company's 75% joint venture interest in Eddystone Rail, a unit-train unloading facility and related local pipeline infrastructure near Philadelphia, Pennsylvania that delivers Bakken and other light sweet crude oil to Philadelphia area refineries, as well as business development costs related to Liquids Pipelines activities. Also included in Feeder Pipelines and Other is the South Prairie Region which transports crude oil and NGL from producing fields and facilities in southeastern Saskatchewan and southwestern Manitoba to Cromer, Manitoba where products enter the mainline system to be transported to the United States or eastern Canada. In addition, the Company owns terminals and tankage facilities in Saskatchewan, as well as the Hardisty Contract Terminal and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude pipeline hub in Western Canada.

Results of Operations

Feeder Pipelines and Other adjusted EBIT for the year ended December 31, 2015 was $155 million compared with $119 million for the year ended December 31, 2014. The increase in adjusted EBIT was attributable to higher earnings from Eddystone Rail Project completed in April 2014, incremental earnings from certain storage agreements, higher tolls and throughput on Toledo Pipeline, contributions from Southern Access Extension which was placed into service in December 2015 and higher throughput from the South Prairie Region that was driven by volumes returning to the system from alternative transportation sources, such as rail. Partially offsetting the increase in adjusted EBIT were higher business development costs not eligible for capitalization in the first quarter of 2015, lower average tolls on Olympic Pipeline and higher property taxes relating to Toledo Pipeline in the third quarter of 2015.

BUSINESS RISKS

The risks identified below are specific to the Liquids Pipelines business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

Enbridge is exposed to throughput risk under the CTS on the Canadian Mainline and under certain tolling agreements applicable to other Liquids Pipelines assets, such as the Lakehead System. A decrease in volumes transported can directly and adversely affect revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, operational incidents, regulatory restrictions, system maintenance and increased competition can all impact the utilization of Enbridge's assets.

Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative energy sources and global supply disruptions outside of Enbridge's control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on Enbridge's pipelines. However, the long-term outlook for Canadian crude oil production, particularly from western Canada, and increasing United States domestic production indicates a growing source of potential supply of crude oil.

Under certain contracts, committed shippers are provided with relief from their take-or-pay payment obligations to the extent such shippers are unable to ship committed volumes on a pipeline solely as a result of Canadian Mainline apportionment.

Enbridge seeks to mitigate utilization risks within its control. The market access expansion initiatives, which have had components placed into service over the past several years, and those currently under development have and are expected to further reduce capacity bottlenecks and enhance access to markets for customers. The Company also seeks to optimize capacity and throughput on its existing assets by working with the shipper community to enhance scheduling efficiency and communications, as well as makes continuous improvements to scheduling models and timelines to maximize throughput. Further to the day-to-day improvements sought by the Company, in 2014, Enbridge and EEP announced the $7.5 billion L3R Program. This project will not increase the overall capacity of the mainline system, but upon completion it will support the safety and operational reliability of the overall system and enhance the flexibility on the mainline system allowing the Company to further optimize throughput. Throughput risk is partially mitigated by provisions in the CTS agreement, which allow Enbridge to adjust the applicable L3R Program surcharge if volumes fall below defined thresholds or to negotiate an amendment to the agreement in the event certain minimum threshold volumes are not met.

Operational and Economic Regulation

Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines or operating restrictions or an overall increase in operating and compliance costs.

Regulatory scrutiny over the integrity of liquids pipeline assets has the potential to increase operating costs or limit future projects. Potential regulatory changes could have an impact on the Company's future earnings and the cost related to the construction of new projects. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions. While the Company believes the safe and reliable operation of its assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on the Company.

The Company's liquids pipelines also face economic regulatory risk. Broadly defined, economic regulation risk is the risk regulators or other government entities change or reject proposed or existing commercial arrangements including permits and regulatory approvals for new projects. The Canadian Mainline, Lakehead System and other liquids pipelines are subject to the actions of various regulators, including the NEB and FERC, with respect to the tariffs and tolls of those operations. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on the Company's revenues and earnings. Delays in regulatory approvals could result in cost escalations and construction delays, which also negatively impact the Company's operations.

The Company believes that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers that govern the majority of the Company's liquids pipeline assets. The Company also involves its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations as well as in the establishment of tariffs and tolls on new and existing pipelines. However, despite the efforts of the Company to mitigate economic regulation risk, there remains a risk that a regulator could overturn long-term agreements between the Company and shippers or deny the approval and permits for new projects.

Competition

Competition may result in a reduction in demand for the Company's services, fewer project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets.

Other competing carriers available to ship western Canadian liquid hydrocarbons to markets in Canada and the United States represent competition to the Company's liquids pipelines network. Competition also arises from proposed pipelines that seek to access markets currently served by the Company's liquids pipelines, such as proposed projects to the Gulf Coast or eastern markets. Competition also exists from proposed projects enhancing infrastructure in the Alberta regional oil sands market. The Mid-Continent and Bakken systems also face competition from existing competing pipelines, proposed future pipelines and existing and alternative gathering facilities, predominately rail. Competition for storage facilities in the United States includes large integrated oil companies and other midstream energy partnerships. Additionally, volatile crude price differentials and insufficient pipeline capacity on either Enbridge or other competitor pipelines can make transportation of crude oil by rail competitive, particularly to markets not currently serviced by pipelines.

The Company believes that its liquids pipelines continue to provide attractive options to producers in the WCSB due to its competitive tolls and flexibility through its multiple delivery and storage points. Enbridge's current complement of growth projects to expand market access and to enhance capacity on the Company's pipeline system combined with the Company's commitment to project execution is expected to further provide shippers reliable and long-term competitive solutions for oil transportation. The Company's existing right-of-way for the mainline system also provides a competitive advantage as it can be difficult and costly to obtain rights of way for new pipelines traversing new areas. The Company also employs long-term agreements with shippers, which also mitigate competition risk by ensuring consistent supply to the Company's liquids pipelines network.

Foreign Exchange and Interest Rate Risk

The CTS agreement for the Canadian Mainline exposes the Company to risks related to movements in foreign exchange rates and interest rates. Foreign exchange risk arises as the Company's IJT under the CTS is charged in United States dollars. These risks have been substantially managed through the Company's hedging program by using financial contracts to fix the prices of United States dollars and interest rates. Certain of these financial contracts do not qualify for cash flow hedge accounting and, therefore, the Company's earnings are exposed to associated changes in the mark-to-market value of these contracts.

GAS DISTRIBUTION

EARNINGS BEFORE INTEREST AND INCOME TAXES

	2015	2014
(millions of Canadian dollars)		
Enbridge Gas Distribution Inc. (EGD)	**342**	305
Noverco Inc. (Noverco)	**53**	45
Other Gas Distribution and Storage	**51**	41
Adjusted earnings before interest and income taxes	**446**	391
EGD - colder than normal weather	**15**	48
EGD - employee severance cost adjustment	**6**	-
Noverco - changes in unrealized derivative fair value loss	**(12)**	(7)
Earnings before interest and income taxes	**455**	432

Adjusted EBIT from Gas Distribution was $446 million for the year ended December 31, 2015 compared with $391 million for the year end December 31, 2014. EGD 2015 and 2014 results reflected rates as established under EGD's customized IR Plan. EGD generated higher adjusted EBIT in 2015 primarily due to an increase in distribution charges that resulted from an increased asset base, as well as customer growth. Stronger operating earnings from Gaz Metro Limited Partnership (Gaz Metro) due to a favourable Exchange Rate and incremental contributions from new assets drove higher Noverco adjusted EBIT in 2015 compared with 2014. In 2015, adjusted EBIT from Other Gas Distribution and Storage reflected the absence of a contract loss that Enbridge Gas New Brunswick Inc. (EGNB) incurred in 2014.

ENBRIDGE GAS DISTRIBUTION INC.

EGD is Canada's largest natural gas distribution company and has been in operation for more than 160 years. It serves over two million customers in central and eastern Ontario and parts of northern New York State. EGD's utility operations are regulated by the OEB and the New York State Public Service Commission.

Incentive Rate Plan

EGD's 2015 and 2014 rates were set in accordance with parameters established by the customized IR Plan. The customized IR Plan was approved in 2014 by the OEB, with modifications, for 2014 through 2018, inclusive of the requested capital investment amounts and an incentive mechanism providing the opportunity to earn above the allowed ROE.

The customized IR Plan provides the methodology for establishing rates for the distribution of natural gas for a five-year period from 2014 through 2018. Within annual rate proceedings for 2015 through 2018, the customized IR Plan requires allowed revenues and corresponding rates to be updated annually for select items including the rate of return to be earned on the equity component of its rate base. The OEB also approved the adoption of a new approach for determining net salvage percentages to be included within EGD's approved depreciation rates, as compared with the traditional approach previously employed. The new approach results in lower net salvage percentages for EGD, and therefore lowers depreciation rates and future removal and site restoration reserves.

For the year ended December 31, 2015, EGD's rates were set according to the OEB approved settlement agreement (April 2015) and the final rate order (May 2015). The rates approved as part of the 2015 rate application represented the second year of the Company's customized IR Plan.

For the year ended December 31, 2014, EGD's rates were set by the OEB's July 2014 decision, and subsequent August 2014 decision and rate order in the Company's customized IR application.

In order to align the interest of customers with the Company's shareholders, the customized IR Plan includes an earnings sharing mechanism, whereby any return over the allowed rate of return for a given year under the customized IR Plan is to be shared equally with customers. For the years ended

December 31, 2015 and 2014, EGD recognized $7 million and $12 million, respectively, as a return of revenues to customers in relation to the earnings sharing mechanism.

Results of Operations

As EGD's operations are rate-regulated and its revenues are directly impacted by items such as depreciation, financing charges and current income taxes, the adjusted EBIT measure for EGD is less indicative of business performance. In light of the nature of the regulated model for EGD's business, the following supplemental adjusted earnings information is also provided to facilitate an understanding of EGD's results from operations:

EGD Earnings

	2015	2014
(millions of Canadian dollars)		
Adjusted earnings before interest and income taxes	**342**	305
Interest expense	**(153)**	(150)
Income taxes	**(18)**	(10)
Adjusting items in respect of:		
Interest expense	**4**	-
Income taxes	**5**	13
Adjusted earnings	**180**	158
EGD - colder than normal weather	**11**	36
EGD - changes in unrealized derivative fair value loss	**(3)**	-
EGD - employee severance cost adjustment	**4**	-
Earnings attributable to common shareholders	**192**	194

EGD adjusted earnings for the year ended December 31, 2015 were $180 million compared with $158 million for the year ended December 31, 2014. While both years reflected rates as established under the customized IR Plan, the higher adjusted earnings in 2015 were primarily attributable to an increase in distribution charges that resulted from an increased asset base, as well as customer growth during the year in excess of expectations embedded in rates. However, the timing of higher income taxes and operating and administrative expenses recorded in the fourth quarter of 2015 drove a decrease in quarter-over-quarter adjusted earnings.

NOVERCO

Enbridge owns an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in preferred shares. Noverco is a holding company that owns approximately 71% of Gaz Metro, a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the province of Quebec and the state of Vermont. Noverco also holds, directly and indirectly, an investment in Enbridge common shares. A significant portion of the Company's earnings from Noverco is in the form of dividends on its preferred share investments which are based on the yield of 10-year Government of Canada bonds plus a margin of 4.3% to 4.4%.

Results of Operations

Noverco adjusted EBIT was $53 million for the year ended December 31, 2015 compared with $45 million for the year ended December 31, 2014. The increase in year-over-year adjusted EBIT reflected stronger operating earnings from Gaz Metro due to a favourable Exchange Rate on Gaz Metro's United States based business and incremental contributions from new assets. Partially offsetting the higher adjusted EBIT was lower preferred share dividend income based on lower yield of 10-year Government of Canada bonds.

OTHER GAS DISTRIBUTION AND STORAGE

Other Gas Distribution includes natural gas distribution utility operations in Quebec and New Brunswick, the most significant being EGNB which is wholly-owned and operated by the Company. EGNB operates the natural gas distribution franchise in the province of New Brunswick, has approximately 12,000 customers and is regulated by the New Brunswick Energy and Utilities Board (EUB).

Results of Operations
Other Gas Distribution and Storage adjusted EBIT was $51 million for the year ended December 31, 2015 compared with $41 million for the year ended December 31, 2014. The increase in adjusted EBIT reflected the absence of a loss that EGNB incurred in 2014 under a contract to sell natural gas to the province of New Brunswick. Due to an abnormally cold winter in the first quarter of 2014, costs associated with the fulfilment of the contract were higher than the revenues received. Excluding the impact of the above noted contract which expired in October 2014, EGNB adjusted EBIT increased slightly in 2015 due to higher distribution revenues.

Enbridge Gas New Brunswick Inc. – Regulatory Matters
In April 2012, the Company commenced an action against the Government of New Brunswick in the New Brunswick courts, seeking damages for breach of contract. The action seeks recovery of damages alleged to have arisen due to various breaches of the General Franchise Agreement with EGNB, under which EGNB operates in the province.

In May 2012, the Company also commenced a separate application to the New Brunswick courts to challenge elements of the Government's rates and tariffs regulation, as it then existed. Ultimately, the Company was successful in defeating the part of the rates and tariffs regulation that capped rates according to a maximum revenue-to-cost ratio. Consequently, EGNB has been able to recover substantially all of its revenue requirement since August 2013, when the successful result of this legal challenge was first implemented into rates.

On February 4, 2014, EGNB commenced second action against the Government of New Brunswick in the New Brunswick courts. The action seeks damages for improper extinguishment of a deferred regulatory asset that was eliminated from EGNB's Consolidated Statements of Financial Position in 2012, due to legislative and regulatory changes enacted by the Government of New Brunswick in that year. A trial of the action was heard by the New Brunswick courts in February 2016. There has been no decision yet issued on the matter.

There is no assurance that either of the two actions presently maintained by EGNB against the Province of New Brunswick will be successful or will result in any recovery.

BUSINESS RISKS
The risks identified below are specific to Gas Distribution business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Economic Regulation
The utility operations of Gas Distribution are regulated by the OEB and EUB among others. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which Gas Distribution operates. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position, or that would have been recorded on the Consolidated Statements of Financial Position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

The Company seeks to mitigate economic regulation risk by maintaining regular and transparent communication with regulators and intervenors on rate negotiations. The terms of rate negotiations are also reviewed by the Company's legal, regulatory and finance teams. The approval of the five-year customized IR Plan in 2014 also provides a level of stability by having a longer-term agreement with the OEB which allows EGD to recover its expected capital investments under the agreement, as well as an opportunity to earn above the OEB allowed ROE. Under the customized IR Plan, EGD is permitted to recover, with OEB approval, certain costs that were beyond management control, but that were necessary for the maintenance of its services. The customized IR Plan also includes a mechanism to reassess the customized IR Plan and return to cost of service if there are significant and unanticipated developments that threaten the sustainability of the customized IR Plan. The above noted terms set out in the settlement agreement mitigate the Company's risk to factors beyond management's control.

Natural Gas Cost Risk
EGD does not profit from the sale of natural gas nor is it at risk for the difference between the actual cost of natural gas purchased and the price approved by the OEB for inclusion in distribution rates. This difference is deferred as a receivable from or payable to customers until the OEB approves its refund or collection. EGD monitors the balance and its potential impact on customers and may request interim rate relief to recover or refund the natural gas cost differential. While the cost of natural gas does not impact EGD's earnings, it does affect the amount of EGD's investment in gas in storage. The OEB also determines the timing of payment or collection from customers which can have an impact on EGD's working capital during the period in which costs are expected to be recovered.

EGNB is also subject to natural gas cost risk as increases in natural gas prices that cannot be fully recovered from customers in the current period can negatively impact cash flow. Increased commodity costs will also impact the amount that may be charged in future distribution rates due to EGNB's regulatory structure.

Volume Risk
Since customers are billed on a volumetric basis, EGD's ability to collect its total revenue requirement (the cost of providing service) depends on achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers.

Weather is a significant driver of delivery volumes, given that a significant portion of EGD's customer base uses natural gas for space heating. Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continue to place downward pressure on consumption. In addition, conservation efforts by customers may further contribute to a decline in annual average consumption.

Sales and transportation of gas for customers in the residential and small commercial sectors account for approximately 80% of total distribution volume. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions from all market sectors are important as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn its expected ROE due to other forecast variables, such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector. EGNB is also subject to volume risk as the impact of weather conditions on demand for natural gas could result in earnings fluctuations.

GAS PIPELINES AND PROCESSING

EARNINGS BEFORE INTEREST AND INCOME TAXES

	2015	2014
(millions of Canadian dollars)		
Aux Sable	**(3)**	45
Alliance Pipeline	**151**	135
Vector Pipeline	**28**	24
Canadian Midstream	**87**	60
Enbridge Offshore Pipelines (Offshore)	**14**	12
US Midstream	**73**	30
Other	**(14)**	(13)
Adjusted earnings before interest and income taxes	**336**	293
Aux Sable - accrual for commercial arrangements	**(30)**	-
Alliance Pipeline - write-down of regulatory balances	**8**	-
Alliance Pipeline - changes in unrealized derivative fair value loss	**(15)**	(6)
Offshore - gain on sale of non-core assets	**6**	22
US Midstream - goodwill impairment loss	**(440)**	-
US Midstream - asset impairment loss	**(20)**	(18)
US Midstream - changes in unrealized derivative fair value gains/(loss)	**(62)**	180
US Midstream - transfer of contracts	**(13)**	-
US Midstream - make-up rights adjustment	**1**	(4)
Earnings/(loss) before interest and income taxes	**(229)**	467

Adjusted EBIT from Gas Pipelines and Processing was $336 million for the year ended December 31, 2015 compared with $293 million for the year ended December 31, 2014. The year-over-year increase in adjusted EBIT was driven primarily by higher take-or-pay fees on Canadian Midstream assets, higher adjusted EBIT from Alliance Pipeline driven by lower operating costs and a stronger United States dollar, and higher contributions from US Midstream resulting from cost reduction initiatives as well as a stronger United States dollar. Partially offsetting these increases were unfavourable market conditions in Aux Sable in 2015. Lower fractionation margins and the loss of a producer processing contract at the Palermo Conditioning Plant have contributed to lower Aux Sable earnings. Aux Sable 2015 results were also negatively impacted by costs associated with feedstock supply.

Additional details on items impacting Gas Pipelines and Processing Services EBIT include:

- US Midstream EBIT for 2015 included a goodwill impairment charge related to the Company’s United States natural gas and NGL businesses due to a prolonged decline in commodity prices which has reduced producers’ expected drilling programs and negatively impacted volumes on the Company’s natural gas and NGL systems.
- US Midstream EBIT for 2015 and 2014 reflected asset impairment charges in relation to a non-core propylene pipeline asset, following finalization of a contract restructuring with the primary customer.
- US Midstream EBIT for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to risk manage commodity price exposures.

AUX SABLE

Enbridge owns a 42.7% interest in Aux Sable US and Aux Sable Midstream US, and a 50% interest in Aux Sable Canada (together, Aux Sable). Aux Sable US owns and operates a NGL extraction and fractionation plant at Channahon, Illinois, outside Chicago, near the terminus of Alliance Pipeline. The plant extracts NGL from the liquids-rich natural gas transported on Alliance Pipeline as necessary for Alliance Pipeline to meet gas quality specifications of downstream transmission and distribution companies and to take advantage of positive fractionation spreads.

Aux Sable US sells its NGL production to a single counterparty under a long-term contract. Aux Sable receives a fixed annual fee and a share of any net margin generated from the business in excess of specified natural gas processing margin thresholds (the upside sharing mechanism). In addition, Aux Sable is compensated for all operating and maintenance costs, and subject to certain limits, costs incurred to source feedstock supply and capital costs associated with its facilities. The counterparty supplies all make-up gas and fuel gas requirements of the Aux Sable plant. The contract is for an initial term of 20 years, expiring March 31, 2026, and may be extended by mutual agreement for 10-year terms.

Aux Sable also owns facilities upstream of Alliance Pipeline that deliver liquids-rich gas volumes into the pipeline for further processing at the Aux Sable plant. These facilities include the Palermo Conditioning Plant and the Prairie Rose Pipeline in the Bakken area of North Dakota, owned and operated by Aux Sable Midstream US; as well as Aux Sable Canada's interests in the Montney area of British Columbia comprising Septimus Pipeline and a 22% interest it acquired effective October 1, 2015 in the Septimus and Wilder Gas Plants in exchange for its previously held 50% ownership interest in the Septimus Plant.

Aux Sable Canada has contracted capacity on the Septimus Pipeline and the Septimus and Wilder Gas Plants to a producer under a 10-year take-or-pay contract which provides for a return on and of invested capital. Actual operating costs are recovered from the producer. In 2015, the majority of capacity at the Palermo Gas Plant and on the Prairie Rose Pipeline was contracted to producers under take-or-pay contracts. Several producers' contract commitments will decline over the next few years while certain producer contract commitments will continue through 2020 under long-term take-or-pay contracts or with life-of-lease reserve dedication. Additional revenues are earned by Aux Sable based on a sharing of available NGL margin with producers.

In September 2014, Aux Sable US received a Notice and Finding of Violation (NFOV) from the United States Environmental Protection Agency (EPA) for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable's Channahon, Illinois facility. As part of the ongoing process of responding to the September 2014 NFOV, Aux Sable discovered what it believes to be an exceedance of currently permitted limits for Volatile Organic Material. Aux Sable received a second NFOV from the EPA in April 2015 in connection with this potential exceedance. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. Initial settlement proposal with the EPA confirms the amount will not be material.

Results of Operations

Aux Sable reported adjusted loss before interest and taxes of $3 million for the year ended December 31, 2015 compared with adjusted EBIT of $45 million for the year ended December 31, 2014. Aux Sable's operations include both a Canadian and United States component. Within Aux Sable adjusted EBIT for the year ended December 31, 2015 was US$4 million (2014 - US$30 million) from its United States' operations.

Lower fractionation margins resulting from a weaker commodity price environment, absence of contributions from the upside sharing mechanism, costs associated with feedstock supply and the loss of a producer processing contract at the Palermo Conditioning Plant were the main drivers behind the year-over-year decreases in adjusted EBIT.

Aux Sable Feedstock Supply

Aux Sable secures NGL feedstock for its Channahon Plant through Rich Gas Premium (RGP) contracts with producers, with varying terms ranging up to a maximum of seven years. RGP contracts provide for producers and Aux Sable to share in the value of the liquids-rich natural gas (both residual dry gas and extracted NGL) transported on the Alliance Pipeline. RGP contract volumes increased as of December 1, 2015, following the termination of essentially all of Alliance Pipeline's initial long-term transportation contracts. Effective December 1, 2015, producers have contracted for firm transportation service under Alliance Pipeline's New Service Framework, and either transport volumes to Aux Sable's Channahon Plant or to the new Alliance Trading Point (ATP), notionally located on Alliance Pipeline Canada. Aux Sable purchases RGP gas volumes delivered to ATP and through corresponding gas sales contracts, assignments or other arrangements with counterparties, Aux Sable facilitates the transport of purchased gas to the Channahon Plant. For further details on Alliance Pipeline Recontracting, refer to *Gas Pipeline and Processing – Alliance Pipeline – Alliance Pipeline Recontracting.*

Business Risks

The risks identified below are specific to Aux Sable. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Commodity Price Risk

Aux Sable's NGL margin earned through the upside sharing mechanism is subject to commodity price risk arising from the price differential between the cost of natural gas and the value achieved from the sale of extracted NGL after the fractionation process. Aux Sable is also subject to the value of natural gas on the Alliance Pipeline supplied by certain of its RGP producers. To mitigate this natural gas supply risk, Aux Sable has entered into a variety of contracts with counterparties. Commodity price risk created from Aux Sable's RGP contracts and through the upside sharing mechanism is closely monitored and must comply with its formal risk management policies that are consistent with the Company's risk management practices. These risks may be mitigated by Aux Sable or through the Company's risk management activities.

Asset Utilization

A decrease in gas volumes or a decrease in the NGL content of the gas stream delivered by Alliance Pipeline to the Aux Sable plant can directly and adversely affect margins earned. Aux Sable is well-positioned to offer RGP contracts, when necessary, to producers within the liquids-rich Montney, Duvernay and Bakken plays that are located in close proximity to Alliance Pipeline to mitigate these risks.

ALLIANCE PIPELINE

The Alliance Pipeline, which includes both Alliance Pipeline Canada and Alliance Pipeline US, consists of approximately 3,000 kilometres (1,864 miles) of integrated, high-pressure natural gas transmission pipeline and approximately 860 kilometres (534 miles) of lateral pipelines and related infrastructure. Alliance Pipeline transports liquids-rich natural gas from northeast British Columbia, northwest Alberta and the Bakken area in North Dakota to the Alliance Chicago gas exchange hub downstream of the Aux Sable NGL extraction and fractionation plant at Channahon, Illinois. Alliance Pipeline US and Alliance Pipeline Canada have annual firm service shipping capacity to deliver 1.455 billion cubic feet per day (bcf/d) and 1.325 bcf/d, respectively. Natural gas transported on Alliance Pipeline downstream of the Aux Sable plant can be delivered to two local natural gas distribution systems in the Chicago area and five interstate natural gas pipelines, providing shippers with access to midwest and eastern natural gas markets.

Prior to December 1, 2015, Alliance Pipeline Canada had transportation service agreements (TSA) with shippers for substantially all of its available firm transportation capacity. The TSA were designed to provide toll revenues sufficient to recover prudently incurred costs of service, including operating and maintenance, depreciation, an allowance for income tax, costs of indebtedness and an allowed ROE of 11.26% after-tax, based on a deemed 70/30 debt/equity ratio. Alliance Pipeline US had similar TSA which allowed for the recovery of the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed ROE of 10.88%. In addition, Alliance Pipeline US negotiated non-renewal charges that are an exit fee for shippers that did not elect to extend their transportation contracts. The initial term of the TSA expired in December 2015, with the exception of a small proportion of shippers that elected to extend their contracts beyond 2015.

Alliance Pipeline Recontracting

In 2013, Alliance Pipeline announced a new services framework and the related tolls and tariff provisions required to implement the new services (collectively, New Services Framework). On June 30, 2015 and July 9, 2015, Alliance Pipeline received regulatory approval from the FERC and the NEB, for the United States and Canadian segments of the pipeline, respectively, for the New Services Framework. Shipments under the New Services Framework commenced December 1, 2015. As part of its acceptance of Alliance Pipeline US' New Services Framework, the FERC set all issues related to the proposed elimination of

Authorized Overrun Service and Interruptible Transportation revenue crediting, and the maintenance of Alliance Pipeline US' existing recourse rates, for hearing. The negotiated reservation rates contained in the Precedent Agreements were converted into negotiated rate transportation contracts as part of the New Services Framework and will not be part of this hearing. As part of the Canadian portion of the New Services Framework, the NEB granted pricing discretion for interruptible transportation and seasonal firm service with all associated revenues accruing to Alliance Pipeline Canada. Alliance Pipeline has successfully re-contracted its annual firm service capacity with an average contract length of approximately five years.

Pursuant to the New Services Framework, Alliance Pipeline retains exposure to potential variability in certain future costs and market based revenues generated from services provided beyond annual firm transport service. As such, the majority of Alliance Pipeline's operations no longer meet all of the criteria required for the continued application of rate-regulated accounting treatment and a derecognition of regulatory balances as at June 30, 2015 was required. A pre-tax gain of approximately $8 million was recorded in EBIT due to the derecognition of regulatory liabilities within Alliance Pipeline during the second quarter of 2015.

Results of Operations

Alliance Pipeline reported adjusted EBIT of $151 million for the year ended December 31, 2015, which represents EBIT from the Company's 50% equity investment in Alliance Pipeline, compared with adjusted EBIT of $135 million for the year ended December 31, 2014. This increase in adjusted EBIT was attributable to lower operating costs, a stronger United States dollar and strong demand in December 2015 for interruptible service under its New Services Framework. These increases were partially offset by a shutdown of Alliance Pipeline Canada for six days in August 2015 after an amount of hydrogen sulfide entered its mainline pipeline through an upstream operator, which resulted in Alliance Pipeline issuing demand charge credits to its shippers. Alliance Pipeline is pursuing avenues to recover these costs.

Business Risks

The risks identified below are specific to Alliance Pipeline. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

Currently, natural gas pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline to date has been relatively unaffected by the excess supply environment as the Alliance Pipeline was successfully recontracted. Further, Alliance Pipeline is well positioned to deliver incremental liquids-rich gas production from developments in the Montney, Duvernay and Bakken regions to large natural gas markets and, following extraction and fractionation at the Aux Sable NGL extraction and fractionation plant, to deliver NGL to growing markets. As noted above, Alliance Pipeline's New Services Framework also allows for the provision of services beyond annual firm transport service, at market rates, further supporting asset utilization.

Competition

Alliance Pipeline faces competition for pipeline transportation services to the Chicago area from both existing pipelines and proposed pipeline projects from existing and new gas developments throughout North America. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by the Alliance Pipeline because of location, facilities or other factors. In addition, any new, existing, or upgraded pipelines could charge tolls or rates or provide transportation services to locations that result in greater net profit for shippers, with the effect of reducing future supply for the Alliance Pipeline. The ability of the Alliance Pipeline to cost-effectively transport liquids-rich gas and its proximity to the liquids-rich Montney, Duvernay and Bakken plays serve to enhance its competitive position.

Economic Regulation

Alliance Pipeline is subject to regulation by the NEB in Canada and the FERC in the United States. Under the New Services Framework, effective December 1, 2015, Alliance Pipeline has contracted with shippers under terms as approved by the NEB in Canada and the FERC in the United States. Firm service tolls are fixed for the duration of the contracts' terms.

VECTOR PIPELINE

Vector, which includes both the Canadian and United States portions of the pipeline system, consists of 560 kilometres (348 miles) of mainline natural gas transmission pipeline between the Chicago, Illinois hub and a storage complex at Dawn, Ontario. Vector's primary sources of supply are through interconnections with Alliance Pipeline, Northern Border Pipeline and Guardian Pipeline in Joliet, Illinois. Vector has the capacity to deliver a nominal 1.3 bcf/d and in 2015 it operated at or near capacity. The Company provides operating services to and holds a 60% joint venture interest in Vector.

Results of Operations

Vector adjusted EBIT for the year ended December 31, 2015 was $28 million compared with $24 million for the year ended December 31, 2014. Vector's operations include a Canadian and United States component. Within Vector adjusted EBIT for the year ended December 31, 2015 was US$20 million (2014 - US$18 million) from its United States' operations.

Excluding the impact of foreign exchange translation to Canadian dollars, Vector adjusted EBIT for the year ended December 31, 2015 was comparable to the corresponding 2014 period. The positive effects of lower operating expenses were offset by lower year-over-year transportation revenues as unusually high demand for natural gas transport was experienced during abnormal winter weather conditions in the first quarter of 2014. The slight increase in EBIT was due to a strengthening United States dollar compared with the Canadian dollar. EBIT from the United States portion of Vector was translated at a higher Exchange Rate in 2015 compared with 2014 resulting in the overall increase in Vector adjusted EBIT in 2015.

Transportation Contracts

Vector's total long haul capacity was 84% contracted under firm service agreements at December 31, 2015 and fully contracted at April 30, 2016. Approximately 27% of long haul capacity is through firm negotiated rate transportation contracts with shippers and approved by the FERC, while the remaining firm service contracts are sold at market rates.

In December 2015, shippers under negotiated rate transportation contracts which represent 20% of the system's long haul capacity elected to extend their commitments through December 1, 2019 and preserve the option to extend their contracts on an annual basis. Vector is entitled to additional compensation from negotiated rate transportation shippers that terminate their contracts prior to the November 30, 2020 expiry date.

In late 2014 and early 2015, Vector signed precedent agreements with both the proposed NEXUS Pipeline and Energy Transfer Partners L.P.'s Rover Pipeline project, to provide transportation service to the Dawn natural gas market hub. Both projects are in the development stage and are subject to FERC approval. These pipeline projects are proposed to enter service during the second half of 2017.

Transportation service on Vector is provided through a number of different forms of service agreements, including Firm Transportation Service, Interruptible Transportation Service and Backhaul Service. Vector is an interstate natural gas pipeline with FERC and NEB approved tariffs that establish the rates, terms and conditions governing its service to customers. On the United States portion of Vector, maximum tariff rates are determined using a cost of service methodology and maximum tariff changes may only be implemented upon approval by the FERC. For 2015, the FERC-approved maximum tariff rates included an underlying weighted average after-tax ROE component of 11.2%. On the Canadian portion, Vector is required to file its negotiated tolls calculation with the NEB on an annual basis. Tolls are calculated on a levelized basis that include a rate of return incentive mechanism based on construction costs and are subject to a rate cap. In 2015, maximum tolls include an ROE component of 10.5% after-tax.

Business Risks

The risks identified below are specific to Vector. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

Vector has been minimally impacted by the excess natural gas supply environment that exists throughout North America mainly as a result of its long-term firm service contracts. Vector has entered into precedent agreements to provide transport service to two proposed pipeline projects that will extend back to the Marcellus/Utica supply basin. These arrangements, proposed to commence in 2017, will effectively fill all available delivery capacity from current contract roll-offs scheduled through 2019. Current firm service contracts that amount to approximately 68% of long haul capacity are scheduled to expire during 2016 and 2017.

Competition

Vector faces competition to transport natural gas into Ontario, Canada and other eastern markets from primarily the Marcellus supply region, which may reduce Vector deliveries sourced from its traditional interconnected pipelines in the United States Midwest. Vector manages this risk by focusing on developing long-term relationships with its customers and by providing them value added services. In addition, in 2017, Vector is expected to commence firm service transport based on precedent agreements in place with Rover Pipeline and NEXUS Pipeline projects. Vector will reach its eastern delivery capacity once these projects are in service.

Economic Regulation

The United States portion of Vector is subject to regulation by the FERC. If tariff rates are protested, the timing and amount of any recovery or refund of amounts recorded on the Consolidated Statements of Financial Position could be different from the amounts that are eventually recovered or refunded. In addition, future profitability of the entities could be negatively impacted.

The FERC continues to intensify its oversight of financial reporting, risk standards and affiliate rules and in 2014, the PHMSA issued new pipeline standards and regulations on managing gas pipeline integrity. The Company continues ongoing dialogue with regulatory agencies and participates in industry groups to ensure it is informed of emerging issues in a timely manner.

CANADIAN MIDSTREAM

At December 31, 2015, Canadian Midstream consisted of the Company's 71% investment in the Cabin Gas Plant (Cabin) located 60 kilometres (37 miles) northeast of Fort Nelson, British Columbia in the Horn River Basin, as well as investments in the Pipestone and Sexsmith gathering systems (together, Pipestone and Sexsmith). The Company has a 100% interest in Pipestone and varying interests (55% to 100%) in Sexsmith and its related sour gas gathering, compression and NGL handling facilities, located in the Peace River Arch (PRA) region of northwest Alberta. The Company is the operator of Cabin.

The Canadian Midstream investments are underpinned by 20-year take-or-pay contracts with producers. Return on and of capital is based on the actual costs to purchase or construct the facilities. The Company is not impacted by throughput volumes; however, the Company shares in revenues obtained from available capacity sold to third parties or on volumes that exceed producer take-or-pay levels. Operating costs are passed through to producers.

Phase 1 of Cabin is currently 98% completed. Cabin producers are expected to request the Company to commission and start-up Phase 1 once natural gas price recovers to a more economic level to support the Horn River Basin's dry gas production. Phase 2 construction is approximately 40% complete and is in preservation mode awaiting producer's requests for completion. In December 2012, the Company started earning fees on its total investment made to date on both Phases 1 and 2. Construction of Pipestone and Sexsmith and related facilities were completed in 2014.

In January 2016, the Company reached agreement with Murphy Oil for the purchase of the Tupper Plants within the Montney shale play in northeastern British Columbia, as described under *Growth Projects –*

Commercially Secured Projects. The Tupper Plants, which are currently operating, are designed to process low H2S natural gas and remove a modest level of NGL in order to meet downstream natural gas pipeline specifications. The $0.5 billion transaction closed on April 1, 2016, following required regulatory approvals. Enbridge is the operator of the facilities and will provide gas processing services to area producers and to Murphy Oil under a 20-year take-or-pay contract with an option to extend the contract.

Results of Operations

Canadian Midstream adjusted EBIT was $87 million for the year ended December 31, 2015 compared with adjusted EBIT of $60 million for the year ended December 31, 2014. Higher adjusted EBIT reflected an increase in take-or-pay fees on the Company's investment in Cabin, Pipestone and Sexsmith. Pipestone adjusted EBIT also increased as a result of higher volumes that exceeded take-or-pay levels and due to a full year of incremental adjusted EBIT from the final phase placed into service in June 2014.

Business Risks

The risks identified below are specific to Canadian Midstream. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

Pipestone and Sexsmith are located within the liquids-rich PRA region which has seen significant development by area producers. In 2015, throughput volumes exceeded take-or-pay levels.

Cabin is located in the prolific Horn River Basin, one of the largest gas shale plays in North America. The current low gas price environment has slowed development due to the remote location and the lack of NGL content to supplement producer economics. Accelerated development of the Horn River is expected to be primarily tied to the development of LNG exports currently being pursued by Cabin producers. The nearby Cordova Embayment and Liard Basin share similar characteristics as the Horn River; however, they are at an earlier stage of development.

The Tupper Plants are located within the core of the Montney shale play, which continues to be developed by a number of producers. Although this area of the Montney contains a lower level of NGL content than others, production is supported by strong economics, the result of high initial production rates, ultimate recoveries and predictable low drilling and completion costs, making it one of the most competitive natural gas production regions in North America.

ENBRIDGE OFFSHORE PIPELINES

Offshore is comprised of 11 active natural gas gathering and FERC-regulated transmission pipelines and two active oil pipelines, including the Heidelberg Pipeline that was placed in service in January 2016, for a total capacity of 160,000 bpd, in four major corridors in the Gulf of Mexico, extending to deepwater developments. These pipelines include almost 2,100 kilometres (1,300 miles) of underwater pipe and onshore facilities with total capacity of approximately 6.5 bcf/d. Offshore currently moves approximately 45% of total offshore gas production and 55% of deepwater gas production through its systems in the Gulf of Mexico.

Results of Operations

Offshore adjusted EBIT was $14 million for the year ended December 31, 2015 compared with adjusted EBIT of $12 million for the year ended December 31, 2014. Excluding the impact of foreign exchange translation to Canadian dollars, Offshore adjusted EBIT for the year ended December 31, 2015 was comparable with the corresponding 2014 period. Adjusted EBIT for both years reflected persistent weak gas volumes due to decreased production in the Gulf of Mexico. For the year ended December 31, 2015, Offshore incurred losses from equity investments in certain joint venture pipelines which were offset by contributions from the Jack St. Malo portion of WRGGS that was completed in December 2014. Finally, adjusted EBIT reflected the favourable impact of translating United States dollar earnings at a higher Exchange Rate in 2015.

Transportation Contracts

The primary shippers on the Offshore systems are producers who execute life-of-lease commitments in connection with transmission and gathering service contracts. In exchange, Offshore provides firm capacity for the contract term at an agreed upon rate. The firm capacity made available generally reflects the lease's maximum sustainable production. The transportation contracts allow the shippers to define a maximum daily quantity (MDQ) over the expected production life. Some contracts have minimum throughput volumes that are subject to ship-or-pay criteria, but also provide the shippers with flexibility, subject to advance notice criteria, to modify the projected MDQ schedule to match current delivery expectations. The majority of long-term transport rates are market-based, with revenue generation directly tied to actual production deliveries. Some of the systems operate under a cost-of-service methodology, including certain lines under FERC regulation.

The business model to be utilized for the WRGGS, Big Foot Pipeline, Venice, Heidelberg Pipeline and Stampede Pipeline projects differs from the historic model. These new projects have a base level return that is locked in through either ship-or-pay commitments or fixed demand charge payments. If volumes reach a producer's anticipated levels, the return on these projects may increase. In addition, Enbridge has minimal capital cost risk on these projects and commercial agreements continue to contain life-of-lease commitments. The WRGGS and Big Foot Pipeline project agreements provide for recovery of actual capital costs to complete the project in fees payable by producers over the contract term. The Stampede Pipeline project provides for a capital cost risk sharing mechanism whereby Enbridge is exposed to a portion of the capital costs in excess of an agreed upon target. Conversely, Enbridge can recover in fees from producers a portion of the capital cost savings below the agreed upon target. Adjustments are allowed for certain of the Heidelberg Pipeline's project variables that impact its cost, with Enbridge bearing the residual capital cost risk after these adjustments have been applied.

Business Risks

The risks identified below are specific to Offshore. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

A decrease in gas volumes transported by Offshore natural gas pipelines can directly affect revenues and EBIT. Low natural gas prices, in part due to the prevalence of onshore shale gas, have resulted in reduced investment in offshore exploration activities and producing infrastructure. Offshore diversifies its risk of declining gas production through the construction of crude oil pipelines. A decline in crude oil prices for a sustained period of time could change the potential for future investment opportunities. Further, a sustained decline in either natural gas or crude oil commodity prices could also impact the ability of the Company to recover its investment in long-lived offshore assets.

Competition

There is competition for new and existing business in the Gulf of Mexico, with multiple parties competing to construct and operate export pipelines for future deepwater discoveries. Offshore has been able to capture key opportunities, often allowing it to more fully utilize existing capacity. Offshore's gas pipelines serve a number of strategically located deepwater host platforms, positioning it favourably to make incremental investments for new platform connections and receive additional transportation volumes from new developments that may be tied back to existing host platforms. Offshore is also able to construct pipelines to transport crude oil, diversifying the risk of declining gas production, as demonstrated with the Big Foot Pipeline, Heidelberg Pipeline and Stampede Pipeline projects. Due to natural production decline, offshore pipelines often have available capacity, resulting in significant competition for new developments in the Gulf of Mexico. Competitive dynamics may impact the ability of the Company to recover its investment in long-lived offshore assets.

Natural Disaster Incidents

Adverse weather, such as hurricanes and tropical storms, may impact Offshore's financial performance directly or indirectly. Direct impacts may include damage to offshore facilities resulting in lower throughput, as well as inspection and repair costs. Indirect impacts may include damage to third party production platforms, onshore processing plants and pipelines that may decrease throughput on Offshore's systems.

The occurrence of hurricanes in the Gulf of Mexico increases the cost and availability of insurance coverage. On May 1, 2013, the Company elected not to renew windstorm coverage on its Offshore asset portfolio. The Company expects to reassess the market for windstorm coverage and revisit the possible purchase of coverage in future years as the Company's portfolio of Offshore assets is expected to increase. Enbridge facilities are engineered to withstand hurricane forces and constant monitoring of weather allows for timely evacuation of personnel and shutdown of facilities; however, damages to assets or injuries to personnel may still occur.

US MIDSTREAM

US Midstream consists of the Anadarko, East Texas, North Texas and Texas Express NGL systems, which include natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities, condensate stabilizers and an NGL fractionation facility. In addition, US Midstream has trucking, rail and liquids marketing operations.

Results of Operations

US Midstream adjusted EBIT was $73 million for the year ended December 31, 2015 compared with $30 million for the year ended December 31, 2014. The year-over-year increase in adjusted EBIT reflected improved operating performance, as well as the favourable effect of translating United States dollar earnings to Canadian dollars at higher Exchange Rate in 2015 compared with 2014.

Excluding the impact of foreign exchange translation to Canadian dollars, US Midstream adjusted EBIT for the year ended December 31, 2015 was US$57 million compared with US$28 million for the year ended December 31, 2014. Adjusted EBIT was positively impacted in 2015 by cost reduction efforts undertaken by management resulting in a decrease in contract labour costs and repairs and maintenance costs. Partially offsetting these positive impacts were lower volumes primarily as a result of reduced drilling programs by producers. For Enbridge's economic interest in US Midstream held through EEP, refer to *Liquidity and Capital Resources – Sponsored Vehicles Program – EEP – Economic Interest.*

As noted above, impacting year-over-year adjusted EBIT was the favourable impact of translating United States dollar earnings at a higher Exchange Rate in 2015 due to the strengthening United States dollar versus the Canadian dollar. Similar to Lakehead System, a portion of US Midstream United States dollar EBIT is hedged as part of the Company's enterprise-wide risk mitigation strategy and realized gains and losses from the foreign exchange derivatives instruments are reported within Eliminations and Other. For further details refer to results of *Eliminations and Other*.

Midcoast Energy Partners, L.P. – Drop Down of Interests

EEP holds its natural gas and NGL midstream assets through a combination of direct holding and indirect holdings through MEP, a publicly listed partnership trading on the New York Stock Exchange. On July 1, 2014, EEP completed the sale of a 12.6% limited partnership interest in its natural gas and NGL midstream business to its subsidiary, MEP, for cash proceeds of US$350 million. Upon finalization of this transaction, EEP continued to retain a 2% GP interest, an approximate 52% limited partner interest and all IDR in MEP. However, EEP's direct interest in entities or partnerships holding the natural gas and NGL midstream operations reduced from 61% to 48%, with the remaining ownership held by MEP. The completion of this transaction resulted in a partial monetization of EEP's natural gas and NGL midstream business through sale to noncontrolling interests (being MEP's public unitholders). The proceeds from the drop down provided EEP a cost-effective funding alternative to execute its current liquids pipeline organic growth program.

Business Risks

The risks identified below are specific to US Midstream. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization
US Midstream natural gas gathering, processing and transportation assets are subject to market fundamentals affecting natural gas, NGL and related products. Commodity prices impact the willingness of natural gas producers to invest in additional infrastructure to produce natural gas and, with current low natural gas prices, infrastructure plans have been increasingly deferred or cancelled. These assets are also subject to competitive pressures from third-party and producer-owned gathering systems.

Supply for the marketing operations depends to a large extent on the natural gas reserves and rate of drilling within the areas served by the natural gas business. Demand is typically driven by weather-related factors, with respect to power plant and utility customers, and industrial demand. The US Midstream marketing business uses third party storage to balance supply and demand factors.

Operational and Economic Regulation
Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines or operating restrictions or an overall increase in operating and compliance costs.

US Midstream's economic regulation is driven primarily through certain activities within its intrastate natural gas pipelines, which are regulated by state regulators. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on US Midstream's revenues and earnings. Delays in regulatory approvals could result in cost escalations and construction delays, which also negatively impact operations. Additionally, while the gas gathering pipelines are not currently subject to FERC rate regulation, proposals to more actively regulate intrastate gathering pipelines are currently being considered in certain of the states in which US Midstream operates. In addition, the FERC has also taken an interest in regulating gas gathering systems that connect into interstate pipelines.

Competition
Other interstate and intrastate natural gas pipelines (or their affiliates) and other midstream businesses that gather, treat, process and market natural gas or NGL represent competition to US Midstream. The level of competition varies depending on the location of the gathering, treating and processing facilities. However, most natural gas producers and owners have alternate gathering, treating and processing facilities available to them, including those owned by competitors that are substantially larger than US Midstream.

US Midstream's marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and natural gas producers, independent aggregators and regional marketing companies.

Commodity Price Risk
US Midstream is subject to commodity price risk arising from movements in natural gas and NGL prices and differentials. These risks have been managed by using physical and financial contracts to fix the prices of natural gas and NGL. Certain of these financial contracts do not qualify for cash flow hedge accounting; therefore, US Midstream's EBIT is exposed to associated changes in the mark-to-market value of these contracts.

OTHER
Other is primarily comprised of business development activites for the Company's gas pipelines businesses and Canadian Midstream and related costs not eligible for capitalization.

GREEN POWER AND TRANSMISSION

EARNINGS BEFORE INTEREST AND INCOME TAXES

	2015	2014
(millions of Canadian dollars)		
Green Power and Transmission	**175**	151
Adjusted earnings before interest and income taxes	**175**	151
Green Power and Transmission - changes in unrealized derivative fair value gains/(loss)	**2**	(2)
Earnings before interest and income taxes	**177**	149

Green Power and Transmission includes approximately 1,800 MW of net operating renewable and alternative energy sources. Of this amount, approximately 930 MW of net power generating capacity comes from wind farms located in the provinces of Alberta, Ontario and Quebec and approximately 680 MW of net power generating capacity comes from wind farms located in the states of Colorado, Texas and Indiana. Most of the power produced from these wind farms are sold under long-term PPA. The Company also has three solar facilities located in Ontario and a solar facility located in Nevada, with 100 MW and 50 MW, respectively, of net power generating capacity. Also included in Green Power and Transmission is the Montana-Alberta Tie-Line, the Company's first power transmission asset, a transmission line from Great Falls, Montana to Lethbridge, Alberta.

Results of Operations

Adjusted EBIT from Green Power and Transmission was $175 million for the year ended December 31, 2015 compared with adjusted EBIT of $151 million for the year ended December 31, 2014. Within Green Power and Transmission adjusted EBIT for the year ended December 31, 2015 was US$27 million (2014 - US$30 million) from its United States' operations.

Excluding the impact of foreign exchange translation to Canadian dollars, the year-over-year increase in adjusted EBIT reflected contributions from new wind farms including Blackspring Ridge which commenced commercial operations in the second quarter of 2014 as well as incremental contributions associated with the purchase of additional interests in the Lac Alfred and Massif du Sud wind projects, which closed in the fourth quarter of 2014 as discussed below. However, the United States operations experienced a slight decrease in adjusted EBIT due to weaker wind resources at Cedar Point wind farm.

Adjusted EBIT reflected the favourable impact of translating United States dollar earnings at a higher Exchange Rate in 2015 on the United States businesses within Green Power and Transmission.

Lac Alfred and Massif du Sud Wind Projects

In September 2014, the Company entered into an agreement to purchase additional interests in the 300-MW Lac Alfred and the 150-MW Massif du Sud from existing partner, EDF EN Canada Inc. Under the agreement, Enbridge invested approximately $225 million to acquire an additional 17.5% interest in Lac Alfred and an additional 30% interest in Massif du Sud. The Lac Alfred transaction closed in October 2014, upon which Enbridge held a 67.5% interest in Lac Alfred. The Massif du Sud transaction closed in December 2014, upon which Enbridge held an 80% interest in Massif du Sud.

BUSINESS RISKS

The risks identified below are specific to the Green Power and Transmission business. General risks that affect the Company as a whole are described under *Risk Management and Financial Instruments – General Business Risks*.

Asset Utilization

Earnings from Green Power and Transmission assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for Green Power and Transmission projects are predicted using long-term historical data, wind and solar resources will be subject to natural variation from year to year and from season to season. Any prolonged reduction in wind or solar resources at any of the Green Power and Transmission facilities could lead to decreased earnings for the Company. Additionally, inefficiencies or interruptions of Green Power facilities due to operational disturbances or outages could also impact earnings. The Company mitigates the risk of operational availability by establishing Operations and Maintenance contracts with the original equipment manufacturers that include a negotiated operational performance asset guarantee. The Company also monitors the operational performance and reliability of the assets on a 24-hour basis.

Power produced from Green Power and Transmission assets is also often sold to a single counterparty under PPA or other long-term pricing arrangements. In this respect, the performance of the Green Power and Transmission assets is dependent on each counterparty performing its contractual obligations under the PPA or pricing arrangement applicable to it.

Competition

The Company's Green Power and Transmission assets operate in the North American power markets, which are subject to competition and the supply and demand balance for power in the provinces and states in which they operate. The renewable energy market sector includes large utilities and small independent power producers, which are expected to aggressively compete with the Company for project development opportunities.

ENERGY SERVICES

EARNINGS BEFORE INTEREST AND INCOME TAXES

	2015	2014
(millions of Canadian dollars)		
Energy Services	**61**	42
Adjusted earnings before interest and income taxes	**61**	42
Energy Services - changes in unrealized derivative fair value gains	**264**	688
Earnings before interest and income taxes	**325**	730

Additional details on items impacting Energy Services EBIT include:

- Energy Services EBIT for each period reflected changes in unrealized fair value gains related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory.
- Energy Services adjusted EBIT for 2014 excluded a realized loss of $193 million incurred to close out certain forward derivative financial contracts intended to hedge the value of committed physical transportation capacity in certain markets accessed by Energy Services, but were determined to be no longer effective in doing so.

Energy Services provides energy supply and marketing services to North American refiners, producers and other customers. Crude oil and NGL marketing services are provided by Tidal Energy. This business transacts at many North American market hubs and provides its customers with various services, including transportation, storage, supply management, hedging programs and product exchanges. Tidal Energy is primarily a physical barrel marketing company focused on capturing value from quality, time and location differentials when opportunities arise. To execute these strategies, Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines and storage facilities. Tidal Energy also provides natural gas marketing services, including marketing natural gas to optimize commitments on certain natural gas pipelines. Additionally, Tidal Energy provides natural gas supply, transportation, balancing and storage for third parties, leveraging its natural gas marketing expertise and access to transportation capacity.

Any commodity price exposure created from Tidal Energy's physical business is closely monitored and must comply with the Company's formal risk management policies. To the extent transportation costs and other fees exceed the basis (location) differential, earnings will be negatively affected.

Results of Operations

Adjusted EBIT from Energy Services was $61 million for the year ended December 31, 2015 compared with adjusted EBIT of $42 million for the year ended December 31, 2014. Energy Services operations include a Canadian and United States component. Within Energy Services adjusted EBIT for the year ended December 31, 2015 was US$31 million (2014 - US$60 million loss before interest and income taxes) from its United States' operations.

Excluding the impact of foreign exchange translation to Canadian dollars, the increase in adjusted EBIT in 2015 reflected strong refinery demand for certain crude oil feedstock leading to more favourable tank management opportunities in the first half of 2015. Additionally, the 2014 adjusted EBIT reflected losses realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. During the second and fourth quarters of 2014, the Company closed out a forward component of these derivative contracts which had been determined to be no longer effective.

The favourable tank management opportunities experienced in the first half of 2015 eroded in the second half of the year due to a reduction in refinery demand for certain crude oil feedstock and an increase in offshore crude supply in the Gulf Coast. The lack of favourable tank management opportunities together with the effects of less favourable conditions in certain markets accessed by committed transportation capacity involving unrecovered demand charges, resulted in an adjusted loss before interest and income taxes in the fourth quarter of 2015. Adjusted EBIT from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Adjusted EBIT also reflected the favourable impact of translating United States dollar earnings at a higher Exchange Rate in 2015 on the United States businesses within Energy Services.

Business Risks

The risks identified below are specific to Energy Services. General risks that affect the entire Company are described under *Risk Management and Financial Instruments – General Business Risks*.

Commodity Price Risk

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Volatility in commodity prices and changing marketing conditions could limit margin opportunities. Furthermore, commodity prices could have negative earnings impacts if the cost of the commodity is greater than resale prices achieved by the Company. Energy Services activities are conducted in compliance with and under the oversight of the Company's formal risk management policies, including the implementation of hedging programs to manage exposure to changes in commodity prices, inclusive of exposures inherent within forecasted transactions.

Competition

Energy Services earnings are generated from arbitrage opportunities which, by their nature, can be replicated by other competitors. An increase in market participants entering into similar arbitrage transactions could have an impact on the Company's earnings. The Company's efforts to mitigate competition risk includes diversification of its marketing business by trading at the majority of major hubs in North America and establishing long-term relationships with clients.

ELIMINATIONS AND OTHER

EARNINGS BEFORE INTEREST AND INCOME TAXES

(millions of Canadian dollars)	**2015**	2014
Operating and administrative	**(74)**	(80)
Realized foreign exchange derivative gains/(loss)	**(238)**	8
Other	**66**	12
Adjusted loss before interest and income taxes	**(246)**	(60)
Canadian Restructuring Plan	**(357)**	-
Changes in unrealized derivative fair value loss	**(356)**	(387)
Unrealized intercompany foreign exchange gains	**131**	16
Drop down transaction costs	**(22)**	(35)
Employee severance costs	**(47)**	(6)
Asset impairment loss	**(2)**	-
Gain on sale of assets	**-**	16
Loss before interest and income taxes	**(899)**	(456)

Eliminations and Other includes operating and administrative costs and foreign exchange costs which are not allocated to business segments. Eliminations and Other also includes new business development activities and general corporate investments.

Included in Eliminations and Other adjusted loss before interest and income taxes for the year ended December 31, 2015 was a realized loss of $238 million (2014 - $8 million gain) related to settlements under the Company's foreign exchange risk management program. The Company targets to hedge 80% or more of anticipated consolidated United States denominated earnings from its United States operations utilizing foreign exchange derivative contracts with the objective of enhancing the predictability of its Canadian dollar earnings and ACFFO.

The notional amount of foreign currency derivatives realized during 2015 was US$952 million (2014 - US$910 million) with an average price to sell United States dollars for Canadian dollars at $1.03 (2014 - $1.11). The Exchange Rate for the year ended December 31, 2015 was $1.28 (2014 - $1.10). As the hedged rate was lower than the Exchange Rate in 2015, the Company recognized a realized hedge loss in 2015. The realized loss in Eliminations and Other partially offsets the positive effect of translating the earnings performance of United States dollar denominated businesses at the 2015 Exchange Rate of $1.28 which is reflected in the reported EBIT of the applicable business segments. In 2014, the hedged rate approximated the Exchange Rate and therefore the realized gain was not significant.

Realized gains and losses on this hedging program are reported in their entirety within Eliminations and Other as the Company manages the foreign exchange risk of its United States dollar denominated businesses at an enterprise-wide level. Gains and losses arising on settlements of foreign exchange derivatives hedging transactional exposure arising from foreign denominated revenues or expenses within the Company's Canadian businesses are captured at the business level and reported as part of the EBIT of the applicable segment. For example, gains and losses on hedges of the Canadian Mainline's United States denominated revenue are reported as part of the EBIT from Canadian Mainline. For further details on the Company's other risk management programs refer to *Risk Management and Financial Instruments – Market Risk – Foreign Exchange Risk.*

Other adjusted EBIT increased from $12 million for the year ended December 31, 2014 to $66 million for the year ended December 31, 2015. The increase in adjusted EBIT reflected realized foreign exchange gains from the translation of certain intercompany transactions.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge's growth strategy, particularly in light of the significant level of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside Enbridge's control, including but not limited to financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, the Company actively manages financial plans and strategies to ensure it maintains sufficient liquidity to meet routine operating and future capital requirements. In the near term, the Company generally expects to utilize cash from operations and the issuance of debt, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. Furthermore, the Company targets to maintain sufficient standby liquidity to bridge fund through protracted capital markets disruptions. The Company targets to maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions to enable it to fund all anticipated requirements for approximately one year without accessing the capital markets.

The Company's financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives, including utilization of its sponsored vehicles EEP and the Fund Group.

CAPITAL MARKET ACCESS

The Company and its self-funding subsidiaries ensure ready access to capital markets through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with its funding plan, the Company completed the following public issuances in 2015 and to date in 2016:

Entity	Type of Issuance	Amount
(millions of Canadian dollars, unless stated otherwise)		
Enbridge	Common shares	2,300
EGD	Medium-term notes	570
EPI (via the Fund Group)	Medium-term notes	1,000
EEP	Class A common units	US$294
EEP	Senior notes	US$1,600
ENF	Common shares	1,275

Bank Credit and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge maintains ready access to funds through committed bank credit facilities and it actively manages its bank funding sources to optimize pricing and other terms. The following table provides details of the Company's committed credit facilities at December 31, 2015 and 2014.

December 31,	Maturity	2015 Total Facilities	2015 Draws[1]	2015 Available	2014 Total Facilities
(millions of Canadian dollars)					
Enbridge	2017-2020	**6,988**	**5,692**	**1,296**	9,025
Enbridge (U.S.) Inc.	2017	**4,470**	**1,665**	**2,805**	3,747
EEP	2017-2020	**3,598**	**2,054**	**1,544**	3,045
EGD	2017-2019	**1,010**	**603**	**407**	1,008
The Fund	2018	**1,500**	**11**	**1,489**	500
Enbridge Pipelines (Southern Lights) L.L.C.	2017	**28**	**-**	**28**	23
EPI	2017	**3,000**	**1,346**	**1,654**	300
Enbridge Southern Lights LP	2017	**5**	**-**	**5**	5
MEP	2018	**1,121**	**678**	**443**	986
Total committed credit facilities[2]		**21,720**	**12,049**	**9,671**	18,639

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

2 On August 18, 2014, long-term private debt was issued for $352 million and US$1,061 million related to Southern Lights project financing. The proceeds were utilized to repay the construction credit facilities on a dollar-for-dollar basis.

In addition to the committed credit facilities noted above, the Company also has $349 million (2014 - $361 million) of uncommitted demand credit facilities, of which $185 million (2014 - $80 million) was unutilized as at December 31, 2015.

The Company's net available liquidity of $10,325 million at December 31, 2015 was inclusive of $1,015 million of unrestricted cash and cash equivalents and net of bank indebtedness of $361 million as reported on the Consolidated Statements of Financial Position.

The Company's credit facility agreements include standard events of default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As at December 31, 2015, the Company was in compliance with all debt covenants and expects to continue to comply with such covenants.

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model have enabled Enbridge to manage its credit profile. The Company actively monitors and manages key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at December 31, 2015, the Company's debt capitalization ratio was 65.5% compared with 63.1% as at December 31, 2014.

Following the Company's announcement of the execution of the definitive agreement in connection with the Canadian Restructuring Plan, and ENF receiving shareholder approval thereof, as applicable, certain credit ratings of the Company were revised or affirmed as follows:

- DBRS Limited downgraded the Company's issuer rating and medium-term notes and unsecured debentures rating from A (low) to BBB (high), downgraded the Company's commercial paper rating from R-1 (low) to R-2 (high) and downgraded the Company's preference share rating from Pfd-2 (low) to Pfd-3 (high), all with stable trends.
- Moody's Investor Services, Inc. (Moody's) downgraded the Company's issuer rating and medium-term notes and unsecured debt rating from Baa1 to Baa2 and updated this rating outlook to stable and downgraded the Company's preference share credit rating from Baa3 to Ba1 and updated this rating outlook to stable. Moody's also affirmed the Company's United States commercial paper rating of P-2.
- Standard & Poor's Ratings Services (S&P) downgraded the Company's corporate credit rating and unsecured debt rating from A- to BBB+ and removed these ratings from credit watch and downgraded the Company's preference share credit rating from P-2 to P-2 (low) and removed this rating from credit watch. S&P also affirmed the Company's Canadian commercial paper

credit rating of A-1 (low), removed this rating from credit watch and maintained a global overall A-2 short-term rating and removed this rating from credit watch.

The Company's investment grade credit ratings are a reflection of the low risk nature of the underlying assets and limited exposure to commodity prices and volume risk; its project execution track record; strong dividend coverage; and substantial standby liquidity. All ratings now have a stable outlook and the Company believes that it continues to have appropriate access to financial markets both in Canada and the United States.

The Company invests a portion of its surplus cash in short-term investment grade instruments with creditworthy counterparties. Short-term investments were $27 million as at December 31, 2015 compared with $308 million as at December 31, 2014. Surplus cash at December 31, 2015 provides additional liquidity and can be used to fund the Company's growth projects.

There are no material restrictions on the Company's cash with the exception of cash in trust of $34 million related to cash collateral and for specific shipper commitments. Cash and cash equivalents held by EEP and the Fund Group are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and monthly for the Fund Group. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

Excluding current maturities of long-term debt, at December 31, 2015 and 2014 the Company had a negative working capital position of $1,227 million and $296 million, respectively, which contemplates the realization of assets and the liquidation of liabilities. In both periods, the major contributing factor is the funding of the Company's growth capital program.

Despite this negative working capital, the Company has significant net available liquidity through committed credit facilities and other sources as previously discussed, which allow the funding of liabilities as they become due. As at December 31, 2015, the net available liquidity totalled $10,325 million (2014 - $9,291 million). It is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

December 31,	**2015**	2014
(millions of Canadian dollars)		
Cash and cash equivalents[1]	**1,049**	1,308
Accounts receivable and other[2]	**5,437**	5,745
Inventory	**1,111**	1,148
Bank indebtedness	**(361)**	(507)
Short-term borrowings	**(599)**	(1,041)
Accounts payable and other[3]	**(7,399)**	(6,524)
Interest payable	**(324)**	(264)
Environmental liabilities	**(141)**	(161)
Working capital	**(1,227)**	(296)

1 Includes Restricted cash.
2 Includes Accounts receivable from affiliates.
3 Includes Accounts payable to affiliates.

OPERATING ACTIVITIES
Cash generated from operating activities was $4,571 million for the year ended December 31, 2015 (2014 - $2,547 million). Excluding the timing effect of changes in operating assets and liabilities, the Company has delivered a growing cash flow stream year-over-year.

The Company's cash flows from operating activities in 2015 have increased by $2,024 million compared with 2014. The cash growth delivered by operations is a reflection of the positive factors discussed in *Performance Overview*, which include higher throughput on the Canadian Mainline, higher volumes and tolls on EEP's liquids business, contributions from new liquids pipeline assets placed into service in recent years and strong refinery demand for crude oil feedstock leading to more favourable tank management opportunities for Energy Services. Partially offsetting these positive factors were higher financing costs associated with funding of the Company's growth program.

Enbridge's operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within Energy Services and Gas Distribution, the timing of tax payments, general variations in activity levels within the Company's businesses, as well as timing of cash receipts and payments.

In 2015, the year-over-year change in cash generated from operating activities was impacted by a favourable variance of $1,035 million for changes in operating assets and liabilities, attributable primarily to a negative impact in early 2014 related to significantly higher natural gas prices combined with colder weather which lead to increased natural gas demand within the Company's gas distribution business, resulting in the Company accumulating a significant regulatory receivable as at December 31, 2014. A significant portion of these regulatory receivables was settled in 2015. The year-over year variance was also positively impacted by the normal course factors noted above. Partially offsetting the favourable variance was higher inventory in Energy Services, as a result of increased activity from the completion of the Seaway Pipeline Twin and Flanagan South projects in late 2014.

INVESTING ACTIVITIES
Cash used in investing activities was $7,933 million for the year ended December 31, 2015 (2014 - $11,891) and reflected the Company's continued successful execution of its growth capital program that it has undertaken over recent years as described under *Growth Projects – Commercially Secured Projects.*

A summary of additions to property, plant and equipment for the years ended December 31, 2015 and 2014 is set out below:

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Liquids Pipelines	**5,882**	8,911
Gas Distribution	**858**	610
Gas Pipelines and Processing	**385**	593
Green Power and Transmission	**68**	333
Energy Services	**-**	3
Eliminations and Other	**80**	74
Total capital expenditures	**7,273**	10,524

The timing of growth projects' approval, construction and in-service dates impact the timing of cash requirements. Cash used in investing activities was higher in 2014 as the Company successfully completed its significant growth projects such as Flanagan South and also made significant progress on major components of the Eastern Access Program and Edmonton to Hardisty Expansion project, which were completed in 2015. In 2015 the Company continued its growth program which included significant spending on the GTA and Southern Access Extension projects.

Other notable investing activities over the last two years included the acquisition of the Company's 24.9% interest in the 400-MW Rampion Project in the United Kingdom in 2015, acquisition of Magic Valley and Wildcat wind farms in 2014, and funding of investments in Seaway Pipeline Twin in 2014.

FINANCING ACTIVITIES

Cash generated from financing activities was $2,973 million for the year ended December 31, 2015 (2014 - $9,770 million). The year-over-year reduction of cash generated from financing activities in 2015 reflected lower capital requirements as a result of a combination of timing of capital expenditures, as noted above, and increased cash flow generation from operations.

In 2015, the Company increased its overall debt by $3,663 million (2014 - $9,000 million). The increase resulted from the issuance of medium-term and senior notes, net of repayments, of $2,744 million (2014 - $5,573 million) and increased credit facility and commercial paper draws, net of repayments, of $1,507 million (2014 - $2,693 million), partially offset by a reduction of $588 million in bank indebtedness and short-term borrowings (2014 - increased by $734 million).

Financing activities also include transactions between the Company's sponsored vehicles and their public unitholders, also referred to as noncontrolling interests. In 2015 the Company did not issue any preference shares or common shares through public offerings directly; however, through its affiliates mainly the Fund Group and EEP, the Company raised $1,285 million of net proceeds in equity capital. These contributions in 2015 were partially offset by distributions of $794 million to noncontrolling interests; whereas, in 2014, the Company made distributions, net of contributions, of $79 million to its noncontrolling interests.

During the year ended December 31, 2014, the Company actively issued preference shares and common shares to the public and raised net proceeds of $1,365 million from the issuance of preference shares, and $478 million from the issuance of common shares. With higher preference shares and common shares outstanding as described below, along with an increase in the common share dividend rate, the amount of dividends paid by the Company has increased year-over-year.

Preference Share Issuances

Since July 2011, the Company has issued 260 million preference shares for gross proceeds of approximately $6,527 million with the following characteristics. See *Outstanding Share Data*.

	Gross Proceeds	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars, unless otherwise stated)						
Series B[5]	$500 million	4.0%	$1.00	$25	June 1, 2017	Series C
Series D[5]	$450 million	4.0%	$1.00	$25	March 1, 2018	Series E
Series F[5]	$500 million	4.0%	$1.00	$25	June 1, 2018	Series G
Series H[5]	$350 million	4.0%	$1.00	$25	September 1, 2018	Series I
Series J[5]	US$200 million	4.0%	US$1.00	US$25	June 1, 2017	Series K
Series L[5]	US$400 million	4.0%	US$1.00	US$25	September 1, 2017	Series M
Series N[5]	$450 million	4.0%	$1.00	$25	December 1, 2018	Series O
Series P[5]	$400 million	4.0%	$1.00	$25	March 1, 2019	Series Q
Series R[5]	$400 million	4.0%	$1.00	$25	June 1, 2019	Series S
Series 1[5]	US$400 million	4.0%	US$1.00	US$25	June 1, 2018	Series 2
Series 3[5]	$600 million	4.0%	$1.00	$25	September 1, 2019	Series 4
Series 5[5]	US$200 million	4.4%	US$1.10	US$25	March 1, 2019	Series 6
Series 7[5]	$250 million	4.4%	$1.10	$25	March 1, 2019	Series 8
Series 9[5]	$275 million	4.4%	$1.10	$25	December 1, 2019	Series 10
Series 11[5]	$500 million	4.4%	$1.10	$25	March 1, 2020	Series 12
Series 13[5]	$350 million	4.4%	$1.10	$25	June 1, 2020	Series 14
Series 15[5]	$275 million	4.4%	$1.10	$25	September 1, 2020	Series 16

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

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

4 *Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14) or 2.7% (Series 16)); or US$25 x (number of days in quarter/365) x (three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6)).*

5 *For dividends declared, see* Liquidity and Capital Resources – Financing Activities.

Common Share Issuances

On March 1, 2016, the Company completed the issuance of 56.5 million common shares for gross proceeds of approximately $2.3 billion, inclusive of the shares issued on exercise of the full amount of the underwriters' over-allotment option to purchase an additional 7.4 million common shares. The proceeds are being used to reduce short-term indebtedness pending reinvestment in capital projects and are expected to be sufficient to fulfill equity funding requirements for Enbridge's current commercially secured growth program through the end of 2017 before consideration of the additional equity raised by ENF in April 2016.

On June 24, 2014, the Company completed the issuance of 7.9 million common shares for gross proceeds of approximately $400 million and on July 8, 2014, issued a further 1.2 million common shares pursuant to the underwriters' over-allotment option for gross proceeds of approximately $60 million. The proceeds were used to fund the Company's growth projects, reduce short-term indebtedness and for other general corporate purposes.

Dividend Reinvestment and Share Purchase Plan

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 year ended December 31, 2015, dividends declared were $1,596 million (2014 - $1,177 million), of which $950 million (2014 - $749 million) were paid in cash and reflected in financing activities. The remaining $646 million (2014 - $428 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 years ended December 31, 2015 and 2014, 40.5% and 36.4%, respectively, of total dividends declared were reinvested.

The Enbridge Board of Directors declared the following quarterly dividends on each of December 2, 2015 and April 22, 2016. Dividends declared on December 2, 2015 were payable on March 1, 2016 to shareholders of record on February 16, 2016. Dividends declared on April 22, 2016 are payable on June 1, 2016 to shareholders of record on May 16, 2016.

Common Shares	$0.53000
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13	$0.27500
Preference Shares, Series 15	$0.27500

SPONSORED VEHICLES PROGRAM

The Company utilizes its sponsored vehicles to enhance its enterprise-wide funding program. The Company's drop-down strategy, whereby Enbridge sells mature, stable assets generating reliable cash flows to its sponsored vehicles, involves monetizing assets with the objective of diversifying funding sources and maintaining access to low cost capital.

The Fund Group

In November 2014, Enbridge finalized an agreement to transfer natural gas and diluent pipeline interests to the Fund, a transaction that provided Enbridge with approximately $1.2 billion of net funding for its growth capital program. For further details, refer to *The Fund Group 2014 Drop Down Transaction.* In September 2015, with the completion of the Canadian Restructuring Plan, the Company achieved a significant milestone relating to its sponsored vehicles dropdown strategy in Canada. For further details, refer to *Canadian Restructuring Plan.*

EEP

In the United States, under the sponsored vehicles program, the restructuring of EEP's equity that was completed in 2014 is expected to benefit Enbridge in the longer term by lowering EEP's cost of capital and improving its growth outlook, thus increasing incentive distributions to Enbridge. Further, in January 2015, Enbridge and EEP completed the drop down of Enbridge's 66.7% interest in the United States segment of the Alberta Clipper Pipeline to EEP. Aggregate consideration for the transaction was US$1 billion, consisting of approximately US$694 million of Class E equity units issued to Enbridge by EEP and the repayment of approximately US$306 million of indebtedness owed to Enbridge. Refer to *Liquids Pipelines – Lakehead System – Alberta Clipper Drop Down.*

Economic Interest
Enbridge's ownership interest in EEP is impacted by EEP's issuance and sale of its Class A common units. To the extent Enbridge does not fully participate in these offerings, the Company's economic interest in EEP is reduced. At December 31, 2015, Enbridge's economic interest in EEP was 35.7% (2014 - 33.7%). The Company's average economic interest in EEP during 2015 was 36.0% (2014 - 27.3%). The increase in Enbridge's economic interest in EEP largely reflected the impact of the restructuring of EEP's equity in 2014 as discussed below. Additionally, Enbridge also holds a US$1.2 billion investment in EEP preferred units as further described below under *EEP Preferred Unit Private Placement.*

Common Unit Issuance
In March 2015, EEP completed the issuance of eight million Class A common units for gross proceeds of approximately US$294 million before underwriting discounts and commissions and offering expenses. Enbridge did not participate in the issuance; however, the Company made a capital contribution of US$6 million to maintain its 2% general partner (GP) interest in EEP. EEP used the proceeds from the offering to fund a portion of its capital expansion projects and for general partnership purposes.

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

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

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

Distributions
In July 2014, EEP increased its quarterly distribution from US$0.5435 per unit to common unitholders to US$0.5550. On December 23, 2014, EEP announced it would further increase its quarterly distribution to US$0.5700 per unit to common unitholders following the announcement that the Alberta Clipper Drop Down was finalized. Refer to *Liquids Pipelines – Lakehead System – Alberta Clipper Drop Down*.

In 2015, Enbridge received from EEP, incentive distributions of US$19 million (2014 - US$39 million). Also in 2015, Enbridge received distributions of US$195 million from Class D units (2014 - US$108 million) and Class E units which were issued under the Equity Restructuring and Alberta Clipper Drop Down transactions.

EEP Preferred Unit Private Placement

In 2013, Enbridge invested US$1.2 billion in preferred units of EEP to reduce the amount of near-term external funding required by EEP to fund its share of the Company's organic growth program. On July 30, 2015, Enbridge and EEP reached an agreement to extend the deferral of quarterly cash distribution on these preferred units. The first quarterly cash distribution will now occur in the third quarter of 2018 and the deferred distribution will now be payable in equal amounts over a 12-quarter period beginning the first quarter of 2019.

CONTRACTUAL OBLIGATIONS

Payments due under contractual obligations over the next five years and thereafter are as follows:

	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
(millions of Canadian dollars)					
Long-term debt[1]	30,224	1,987	3,836	4,724	19,677
Capital and operating leases	1,102	123	189	133	657
Long-term contracts	14,445	5,505	3,200	2,187	3,553
Pension obligations[2]	118	118	-	-	-
Total contractual obligations	45,889	7,733	7,225	7,044	23,887

1 *Represents debenture and term note maturities and excludes interest obligations. Changes to the planned funding requirements are dependent on the terms of any debt refinancing agreements.*

2 *Assumes only required payments will be made into the pension plans in 2016. Contributions are made in accordance with independent actuarial valuations as at December 31, 2015. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

CAPITAL EXPENDITURE COMMITMENTS

Included within Long-term contracts in the table above are contracts that the Company has signed for the purchase of services, pipe and other materials totalling $3,993 million which are expected to be paid over the next five years.

TAX MATTERS

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

OTHER LITIGATION

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

OUTSTANDING SHARE DATA[1]

PREFERENCE SHARES

	Number	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3]
Preference Shares, Series A	5,000,000	-	-
Preference Shares, Series B	20,000,000	June 1, 2017	Series C
Preference Shares, Series D	18,000,000	March 1, 2018	Series E
Preference Shares, Series F	20,000,000	June 1, 2018	Series G
Preference Shares, Series H	14,000,000	September 1, 2018	Series I
Preference Shares, Series J	8,000,000	June 1, 2017	Series K
Preference Shares, Series L	16,000,000	September 1, 2017	Series M
Preference Shares, Series N	18,000,000	December 1, 2018	Series O
Preference Shares, Series P	16,000,000	March 1, 2019	Series Q
Preference Shares, Series R	16,000,000	June 1, 2019	Series S
Preference Shares, Series 1	16,000,000	June 1, 2018	Series 2
Preference Shares, Series 3	24,000,000	September 1, 2019	Series 4
Preference Shares, Series 5	8,000,000	March 1, 2019	Series 6
Preference Shares, Series 7	10,000,000	March 1, 2019	Series 8
Preference Shares, Series 9	11,000,000	December 1, 2019	Series 10
Preference Shares, Series 11	20,000,000	March 1, 2020	Series 12
Preference Shares, Series 13	14,000,000	June 1, 2020	Series 14
Preference Shares, Series 15	11,000,000	September 1, 2020	Series 16

COMMON SHARES

	Number
Common Shares - issued and outstanding (voting equity shares)	929,112,973
Stock Options - issued and outstanding (24,715,464 vested)	40,695,719

1 Outstanding share data information is provided as at April 29, 2016.

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

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.

QUARTERLY FINANCIAL INFORMATION

2015	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**7,929**	**8,631**	**8,320**	**8,914**	**33,794**
Earnings/(loss) attributable to common shareholders	**(383)**	**577**	**(609)**	**378**	**(37)**
Earnings/(loss) per common share	**(0.46)**	**0.68**	**(0.72)**	**0.44**	**(0.04)**
Diluted earnings/(loss) per common share	**(0.46)**	**0.67**	**(0.72)**	**0.44**	**(0.04)**
Dividends paid per common share	**0.465**	**0.465**	**0.465**	**0.465**	**1.86**
EGD - warmer/(colder) than normal weather	**(33)**	**6**	**-**	**16**	**(11)**
Changes in unrealized derivative fair value (gains)/loss	**977**	**(296)**	**654**	**45**	**1,380**

2014	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	10,521	10,026	8,297	8,797	37,641
Earnings/(loss) attributable to common shareholders	390	756	(80)	88	1,154
Earnings/(loss) per common share	0.48	0.92	(0.10)	0.11	1.39
Diluted earnings/(loss) per common share	0.47	0.91	(0.10)	0.10	1.37
Dividends paid per common share	0.3500	0.3500	0.3500	0.3500	1.40
EGD - warmer/(colder) than normal weather	(33)	(4)	2	(1)	(36)
Changes in unrealized derivative fair value (gains)/loss	190	(430)	396	164	320

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.

A significant part of the Company's revenues are generated from its energy services operations. Revenues from these operations depend on activity levels, which vary from year to year depending on market conditions and commodity prices. Commodity prices do not directly impact earnings since these earnings reflect a margin or percentage of revenues that depends more on differences in commodity prices between locations and points in time than on the absolute level of prices.

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 flow-through nature of these costs.

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

In addition to the impacts of weather in EGD's franchise area and changes in unrealized gains and losses outlined above, significant items impacting the consolidated quarterly earnings are noted below:

- Included in the fourth quarter of 2015 were employee severance costs in relation to the Company's enterprise-wide reduction of workforce, with a net charge of $25 million to earnings.
- Included in the fourth quarter of 2015 was an asset impairment charge of US$63 million ($11 million after-tax attributable to Enbridge) related to EEP's Berthold rail facility due to the inability to renew committed shipper agreements beyond 2016 or secure sufficient spot volume.

- Included in the third quarter of 2015 were impacts from the transfer of assets between entities under common control of Enbridge in connection with the Canadian Restructuring Plan, resulting in a $247 million loss on the de-designation of interest rate hedges, an $88 million write-off of a regulatory asset in respect of taxes and $16 million of transaction costs.
- Included in the third quarter of 2015 was an after-tax gain of $44 million on the disposal of non-core assets within the Liquids Pipelines segment.
- Included in the second quarter of 2015 was a goodwill impairment charge of $440 million ($167 million after-tax attributable to Enbridge) related to EEP's natural gas and NGL businesses due to a prolonged decline in commodity prices which reduced producers' expected drilling programs and negatively impacted volumes on EEP's natural gas and NGL systems.
- Included in the second quarter of 2015 and fourth quarter of 2014 were the tax impact of asset transfers between entities under common control of Enbridge. The intercompany gains realized by the selling entities have been eliminated from the Company's consolidated financial statements. However, as the transaction involved sale of partnership units, the tax consequences have remained in consolidated earnings and resulted in a charge of $39 million and $157 million, respectively.
- Included in earnings are after-tax gains on the disposal of non-core Offshore assets. The Company recognized gains of $4 million in the second quarter of 2015 and $43 million and $14 million in first and fourth quarters of 2014, respectively. Earnings in the first quarter of 2014 also included a $14 million after-tax gain on the sale of an Alternative and Emerging Technologies investment.
- Included in earnings is the Company's share of after-tax leak remediation costs associated with the Line 6B crude oil release. Remediation costs of $5 million and $12 million were recognized in the second and third quarters of 2014. In the fourth quarter of 2014, the Company recognized an out-of-period adjustment of $5 million to reduce Enbridge's share of leak remediation costs recognized in the third quarter of 2014.
- Included in earnings are after-tax costs of $6 million in the second quarter of 2015 and $4 million in the third quarter of 2014, in connection with the Line 37 crude oil release which occurred in June 2013. Earnings also reflected after-tax insurance recoveries associated with the Line 37 crude oil release of $9 million and $13 million recognized in each of the first quarter and fourth quarter of 2015, as well as $4 million recognized in each of the second quarter and fourth quarter of 2014, respectively.

Finally, the Company is in the midst of a substantial growth 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 under *Growth Projects – Commercially Secured Projects* and *Other Announced Projects Under Development.*

RELATED PARTY TRANSACTIONS

Other than the drop down transactions between Enbridge and its sponsored vehicles, including the Canadian Restructuring Plan, all related party transactions are conducted in the normal course of business and, unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $7 million for the year ended December 31, 2015 (2014 - $7 million).

Certain wholly-owned subsidiaries within the Liquids Pipelines, Gas Distribution, Gas Pipelines and Processing and Energy Services segments, have committed and uncommitted transportation arrangements with several joint venture affiliates that are accounted for using the equity method. Total amounts charged to the Company for transportation services for the year ended December 31, 2015 were $332 million (2014 - $256 million).

A wholly-owned subsidiary within Liquids Pipelines had a lease arrangement with a joint venture affiliate. During the year ended December 31, 2015, expenses related to the lease arrangement totalled $151 million (2014 - $21 million) and were recorded to Operating and administrative expense.

Certain wholly-owned subsidiaries within Gas Distribution and Energy Services segments made natural gas and NGL purchases of $228 million (2014 - $315 million) from several joint venture affiliates during the year ended December 31, 2015.

Natural gas sales of $5 million (2014 - $58 million) were made by certain wholly-owned subsidiaries within the Energy Services segment to several joint venture affiliates during the year ended December 31, 2015.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

Amounts receivable from affiliates include a series of loans to Vector and other affiliates totalling $149 million and $3 million, respectively (2014 - $183 million and nil, respectively), which require quarterly interest payments at annual interest rates ranging from 4% to 12%. These amounts are included in Deferred amounts and other assets.

INTERCOMPANY ACCOUNTS RECEIVABLE SALE

In 2013, certain of EEP's subsidiaries entered into a Receivables Purchase Agreement (the Receivables Agreement) with a wholly-owned subsidiary of Enbridge, whereby Enbridge will purchase on a monthly basis certain trade and accrued receivables of such subsidiaries through December 2016. Pursuant to the Receivables Agreement, at any one point the accumulated purchases, net of collections, shall not exceed US$450 million. The primary objective of the accounts receivable transaction is to further enhance EEP's available liquidity and its cash available from operations for payment of distributions during the next few years until EEP's large growth capital commitments are permanently funded, as well as to provide an annual saving in EEP's cost of funding during this period.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

Foreign Exchange Risk

The Company generates certain revenues, incurs expenses and holds a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

The Company has implemented a policy whereby, at a minimum, it hedges a level of foreign currency denominated earnings exposures over a five year forecast horizon. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. The Company hedges certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 2.0%.

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 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 3.4%.

The Company also monitors its debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt within its Board of Directors approved policy limit of a maximum of 25% floating rate debt as a percentage of total debt outstanding. The Company primarily uses 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, crude oil, power and NGL. The Company employs financial derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. The Company uses primarily non-qualifying derivative instruments to manage commodity price risk.

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

The Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of derivative instruments on the Company's consolidated earnings and consolidated comprehensive income.

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**77**	8
Interest rate contracts	**(275)**	(1,086)
Commodity contracts	**9**	50
Other contracts	**(47)**	13
Net investment hedges		
Foreign exchange contracts	**(248)**	(113)
	(484)	(1,128)
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Foreign exchange contracts[1]	**9**	8
Interest rate contracts[2]	**128**	101
Commodity contracts[3]	**(46)**	4
Other contracts[4]	**28**	(7)
	119	106
De-designation of qualifying hedges in connection with the Canadian Restructuring Plan		
Interest rate contracts[2,5]	**338**	-
	338	-
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**21**	216
Commodity contracts[3]	**5**	(6)
	26	210
Amount of gains/(loss) from non-qualifying derivatives included in earnings		
Foreign exchange contracts[1]	**(2,187)**	(936)
Interest rate contracts[2,5]	**(363)**	4
Commodity contracts[3]	**199**	1,031
Other contracts[4]	**(22)**	7
	(2,373)	106

1 Reported within Transportation and other services revenues and Other expense in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 Reported within Transportation and other services revenues, Commodity revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
5 The amounts above include $338 million for the year ended December 31, 2015 relating to the de-designation of qualifying hedges in connection with the Canadian Restructuring Plan.

LIQUIDITY RISK
Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. However, leading up to the closure of the Canadian Restructuring Plan, the Company did not access the public markets as regularly as it had in previous years. However, once the Canadian Restructuring Plan was closed, Enbridge again began to

access the public debt and equity markets in normal course. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2015. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

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

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

FAIR VALUE MEASUREMENTS

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

GENERAL BUSINESS RISKS

Strategic and Commercial Risks

Public Opinion

Public opinion or reputation risk is the risk of negative impacts on the Company's business, operations or financial condition resulting from changes in the Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which Enbridge operates as well as their opposition to development projects, such as Northern Gateway. Potential impacts of a negative public opinion may include loss of business, delays in project execution, legal action, increased regulatory oversight or delays in regulatory approval and higher costs.

Reputation risk often arises as a consequence of some other risk event, such as in connection with operational, regulatory or legal risks. Therefore, reputation risk cannot be managed in isolation from other risks. The Company manages reputation risk by:

- having health, safety and environment management systems in place, as well as policies, programs and practices for conducting safe and environmentally sound operations with an emphasis on the prevention of any incidents;
- having formal risk management policies, procedures and systems in place to identify, assess and mitigate risks to the Company;
- operating to the highest ethical standards, with integrity, honesty and transparency, and maintaining positive relationships with customers, investors, employees, partners, regulators and other stakeholders;
- building awareness and understanding of the role energy and Enbridge play in people's lives in order to promote better understanding of the Company and its businesses;
- having strong corporate governance practices, including a Statement on Business Conduct, which requires all employees to certify their compliance with Company policy on an annual basis, and whistleblower procedures, which allow employees to report suspected ethical concerns on a confidential and anonymous basis; and
- pursuing socially responsible operations as a longer-term corporate strategy (implemented through the Company's CSR Policy, Climate Change Policy and Aboriginal and Native American Policy).

The Company's actions noted above are the key mitigation actions against negative public opinion; however, the public opinion risk cannot be mitigated solely by the Company's individual actions. The Company actively works with other stakeholders in the industry to collaborate and work closely with government and Aboriginal communities to enhance the public opinion of the Company, as well as the industry in which it operates. ***Unless otherwise specifically stated, none of the content of the policies or initiatives described above are incorporated by reference herein.***

Project Execution

As the Company continues to execute on a large slate of commercially secured growth projects, it continues to focus on completing projects safely, on-time and on-budget. The Company's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, inadequate resources, in-service delays and increasing complexity of projects (collectively, Execution Risk).

Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation and environmental and regulatory permitting. Cost escalations or missed in-service dates on future projects may impact future earnings and cash flows and may hinder the Company's ability to secure future projects. Construction delays due to regulatory delays, third-party opposition, contractor or supplier non-performance and weather conditions may impact project development.

The Company strives to be an industry leader in project execution and through its Major Projects group, it seeks to mitigate project Execution Risk. Major Projects is centralized and has a clearly defined governance structure and process for all major projects, with dedicated resources organized to lead and execute each major project.

Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. Detailed cost tracking and centralized purchasing is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors and those selected are chosen based on the Company's strict adherence to safety including robust safety standards embedded in contracts with suppliers. The Company has assessed work volumes for the next several years across its major projects to optimize the expected costs, supply of services, material and labour to execute the projects. Underpinning this approach is Major Project's Project Lifecycle Gating Control tool which helps to ensure schedule, cost, safety and quality objectives are on track and met for each stage of a project's development and construction.

Consultations with regulators are held in-advance of project construction to enhance understanding of project rationale and ensure applications are compliant and robust, while at all times maintaining a strong focus on integrity and public safety. The Company also actively involves its legal and regulatory teams to work closely with Major Projects to engage in open dialogue with government agencies, regulators, land owners, Aboriginal groups and special interest groups to identify and develop appropriate responses to their concerns regarding the Company's projects.

Operational and Economic Regulation, Permits and Approvals

Many of the Company's operations are regulated and are subject to both operational and economic regulatory risk. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States has changed significantly in past years and there is no assurance that further substantial changes will not occur.

Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines, operating restrictions or shutdown of assets or an overall increase in operating and compliance costs. Regulatory scrutiny over the Company's assets has the potential to increase operating costs or limit future projects. Potential regulatory changes could have an impact on the Company's future earnings and the cost related to the construction of new projects. The Company believes operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators or through industry associations. The Company also develops robust response plans to regulatory changes or enforcement actions. While the Company believes the safe and reliable operation of its assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on the Company.

The Company also faces economic regulation, permits and approvals risk, which broadly defined, is the risk that regulators or other government entities change or reject proposed or existing commercial arrangements including permits and regulatory approvals for new projects. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on the Company's revenues and earnings. Increasing regulatory scrutiny and resulting delays in regulatory permits and approvals could result in cost escalations, construction delays and in-service delays which also negatively impact the Company's operations.

The Company believes that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers that govern the majority of its operations. The Company also involves its legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations as well as in the establishment of tariffs and tolls for these assets. Enbridge retains dedicated professional staff and maintains strong relationships with customers, intervenors and regulators to help minimize economic regulation risk. However, despite the efforts of the Company to mitigate economic regulation risk, there remains a risk that a regulator could overturn long-term agreements between the Company and shippers or deny the approval and permits for new projects.

Planning and Investment Analysis

The Company evaluates expansion projects, acquisitions and divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility and unpredictability in the economy, both locally and globally, change in cost estimates, project scoping and risk assessment could result in a loss in profits for the Company. Large scale acquisitions may involve significant price and integration risk.

The planning and investment analysis process involves all levels of management and Board of Directors' review to ensure alignment across the Company. A centralized corporate development group rigorously evaluates all major investment proposals with consistent due diligence processes, including a thorough review of the asset quality, systems and financial performance of the assets being assessed.

Operational Risks

Environmental Incident

An environmental incident could have lasting reputational impacts to Enbridge and could impact its ability to work with various stakeholders. In addition to the cost of remediation activities (to the extent not covered by insurance), environmental incidents may lead to an increased cost of operating and insuring the Company’s assets, thereby negatively impacting earnings. The Company mitigates risk of environmental incidents through its ORM Plan, which broadly aims to position Enbridge as the industry leader for system integrity, environmental and safety programs. Mitigation efforts continue to focus on efforts to reduce the likelihood of an environmental incident. Under the umbrella of the ORM Plan the Company has continued its maintenance, excavation and repair program which is supported by operating and capital budgets for pipeline integrity. The Company’s $7.5 billion L3R Program, the largest project in the Company’s history, is a further commitment by the Company to its key strategic priority of safety and operational reliability. Once it is completed, the L3R Program will provide a major enhancement to Enbridge’s mainline system by replacing most segments of the Line 3 pipeline with the latest high-strength steel and coating.

Although the Company believes its integrated management system, plans and processes mitigate the risk of environmental incidents, there remains a chance that an environmental incident could occur. The ORM Plan also seeks to mitigate the severity of a potential environmental incident through continued process improvements and enhancements in leak detection processes and alarm analysis procedures. The Company has also invested significant resources to enhance its emergency response plans, operator training and landowner education programs to address any potential environmental incident.

The Company maintains comprehensive insurance coverage for its subsidiaries and affiliates that it renews annually. The insurance program includes coverage for commercial liability that is considered customary for its industry and includes coverage for environmental incidents. The total insurance coverage will be allocated on an equitable basis in the unlikely event multiple insurable incidents exceeding the Company’s coverage limits are experienced by Enbridge and two Enbridge subsidiaries covered by the same policy within the same insurance period.

Public, Worker and Contractor Safety

Several of the Company’s pipeline systems run adjacent to populated areas and a major incident could result in injury to members of the public. A public safety incident could result in reputational damage to the Company, material repair costs or increased costs of operating and insuring the Company’s assets. In addition, given the natural hazards inherent in Enbridge’s operations, its workers and contractors are subject to personal safety risks.

Safety and operational reliability are the most important priorities at Enbridge. Enbridge’s mitigation efforts to reduce the likelihood and severity of a public safety incident are executed primarily through its ORM Plan and emergency response preparedness, as described above in *Environmental Incident.* The Company also actively engages stakeholders through public safety awareness activities to ensure the public is aware of potential hazards and understands the appropriate actions to take in the event of an emergency. Enbridge also actively engages first responders through education programs that endeavour to equip first responders with the skills and tools to safely and effectively respond to a potential incident.

Finally, Enbridge believes in a safety culture where safety incidents are not tolerated by employees and contractors and has established a target of zero incidents. For employees, safety objectives have been incorporated across all levels of the Company and are included as part of an employee’s compensation measures. Contractors are chosen following a rigorous selection process that includes a strict adherence to Enbridge’s safety culture.

Information Technology Security or Systems Incident
The Company's infrastructure, applications and data are becoming more integrated, creating an increased risk that failure in one system could lead to a failure of another system. There is also increasing industry-wide cyber-attacking activity targeting industrial control systems and intellectual property. A successful cyber-attack could lead to unavailability, disruption or loss of key functionalities within the Company's industrial control systems which could impact pipeline operations and potentially result in an environmental or public safety incident. A successful cyber-attack could also lead to a large scale data breach resulting in unauthorized disclosure, corruption or loss of sensitive company or customer information which could have lasting reputational impacts to Enbridge and could impact its ability to work with various stakeholders.

The Company has implemented a comprehensive security strategy that includes a security policy and standards framework, defined governance and oversight, layered access controls, continuous monitoring, infrastructure and network security and threat detection and incident response through a security operations centre. The Company's information technology security operations are consolidated under one leadership structure to increase consistency and compliance with the Company's security requirements across business segments.

Service Interruption Incident
A service interruption due to a major power disruption or curtailment on commodity supply could have a significant impact on the Company's ability to operate its assets and negatively impact future earnings, relationships with stakeholders and the Company's reputation. Specifically, for Gas Distribution, any prolonged interruptions would ultimately impact gas distribution customers. Service interruptions that impact the Company's crude oil transportation services can negatively impact shippers' operations and earnings as they are dependent on Enbridge services to move their product to market or fulfill their own contractual arrangements. The Company mitigates service interruption risk through its diversified sources of supply, storage withdrawal flexibility, backup power systems, critical parts inventory and redundancies for critical equipment. Specifically for Gas Distribution, the GTA project, which was completed in March 2016, will be a key mitigation as the project is expected to provide significant diversification of gas supply to EGD's distribution network and will further reduce the likelihood of a service interruption incident.

Business Environment Risks
Aboriginal Relations
Canadian judicial decisions have recognized that Aboriginal rights and treaty rights exist in proximity to the Company's operations and future project developments. The courts have also confirmed that the Crown has a duty to consult with Aboriginal people when its decisions or actions may adversely affect Aboriginal rights and interests or treaty rights. Crown consultation has the potential to delay regulatory approval processes and construction, which may affect project economics. In some cases, respecting Aboriginal rights may mean regulatory approval is denied or the conditions in the approval make a project economically challenging.

Given this environment and the breadth of relationships across the Company's geographic span, Enbridge has implemented an Aboriginal and Native American Policy. This policy promotes the achievement of participative and mutually beneficial relationships with Aboriginal and Native American groups affected by the Company's projects and operations. Specifically, the policy sets out principles governing the Company's relationships with Aboriginal and Native American people and makes commitments to work with Aboriginal people and Native Americans so they may realize benefits from the Company's projects and operations. Notwithstanding the Company's efforts to this end, the issues are complex and the impact of Aboriginal and Native American relations on Enbridge's operations and development initiatives is uncertain. ***Unless otherwise specifically stated, none of the content of this policy is incorporated by reference herein.***

Special Interest Groups including Non-Governmental Organizations
The Company is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on governments and regulators by special interest groups, including non-governmental organizations. Recent judicial decisions have increased the ability of special interest groups

to make claims and oppose projects in regulatory and legal forums. In addition to issues raised by groups focused on particular project impacts, the Company and others in the energy and pipeline businesses are facing opposition from organizations opposed to oil sands development and shipment of production from oil sands regions.

The Company works proactively with special interest groups and non-governmental organizations to identify and develop appropriate responses to their concerns regarding its projects. The Company is investing significant resources in these areas. Its CSR program also reports on the Company's responsiveness to environmental and community issues. Refer to Enbridge's annual CSR Report, available online at http://csr.enbridge.com for further details regarding the CSR program. ***Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website is incorporated by reference in, or otherwise part of this MD&A.***

CRITICAL ACCOUNTING ESTIMATES

The following critical accounting estimates discussed below have an impact across the various segments of the Company.

DEPRECIATION

Depreciation of property, plant and equipment, the Company's largest asset with a net book value at December 31, 2015 of $64,434 million (2014 - $53,830 million), or 76.1% of total assets, is generally provided on a straight-line basis over the estimated service lives of the assets commencing when the asset is placed in service. When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of the Company's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Company's pipelines as well as the demand for crude oil and natural gas and the integrity of the Company's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Company's business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

ASSET IMPAIRMENT

The Company evaluates the recoverability of its property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate it may not recover the carrying amount of the assets. The Company continually monitors its businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the property, plant and equipment and the recognition of an impairment loss in the Consolidated Statements of Earnings.

The Company also tests goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step involves determining the fair value of the Company's reporting units inclusive of goodwill and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the reporting unit's assets and liabilities.

REGULATORY ASSETS AND LIABILITIES

Certain of the Company's businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the AER and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non-rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the NEB's Land Matters Consultation Initiative (LMCI). Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates. As at December 31, 2015, the Company's significant regulatory assets totalled $1,782 million (2014 - $2,174 million) and significant regulatory liabilities totalled $869 million (2014 - $962 million).

POSTRETIREMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and OPEB to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using the universal method. This method involves complex actuarial calculations using several assumptions including discount rates, which were determined by referring to high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans, expected rates of return on plan assets, health-care cost trend rates, projected salary increases, retirement age, mortality and termination rates. These assumptions are determined by management and are reviewed annually by the Company's actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The shortfall from the expected return on plan assets was $62 million for the year ended December 31, 2015 (2014 - $58 million excess) as disclosed in Note 26, Retirement and Postretirement Benefits, to the 2015 Annual Consolidated Financial Statements. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2015 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Pension Benefits		OPEB	
	Obligation	Expense	Obligation	Expense
(millions of Canadian dollars)				
Decrease in discount rate	209	31	24	1
Decrease in expected return on assets	-	10	-	1
Decrease in rate of salary increase	(43)	(14)	-	-

CONTINGENT LIABILITIES
Provisions for claims filed against the Company are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments are detailed in Note 31, Commitments and Contingencies, of the 2015 Annual Consolidated Financial Statements. In addition, any unasserted claims that later may become evident could have a material impact on the financial results of the Company and certain of the Company's subsidiaries and investments.

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

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

In 2009, the NEB issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the NEB Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The NEB's decision stated that while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the NEB.

Following the NEB's final approval of the collection mechanism and the set-aside mechanism for LMCI, the Company began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trust in accordance with the NEB decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments. Concurrently, the Company reflects the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF ACCOUNTING POLICY
Principles of Consolidation and Noncontrolling Interests
As a result of the Canadian Restructuring Plan, ECT, a subsidiary of the Company, determines its equity investment earnings from EIPLP using the Hypothetical Liquidation at Book Value (HLBV) method. ECT applies the HLBV method to its equity method investments where cash distributions, including both preference and residual distributions, are not based on the investor's ownership percentages. Under the HLBV method, a calculation is prepared at each balance sheet date to determine the amount that ECT would receive if EIPLP were to liquidate all of its assets, as valued in accordance with U.S. GAAP, and distribute that cash to the investors. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period, after adjusting for capital contributions and distributions, is ECT's share of the earnings or losses from the equity investment for the period.

While ECT and EIPLP are both consolidated in the financial statements of Enbridge, the use of the HLBV method by ECT impacts the earnings attributable to redeemable noncontrolling interests reported on

Enbridge's Consolidated Statements of Earnings. The Company continues to recognize Redeemable noncontrolling interests on its Consolidated Statements of Financial Position at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares.

ADOPTION OF NEW STANDARDS

Simplifying the Presentation of Debt Issuance Costs

ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires debt issuance costs related to a recognized debt liability to be presented in the Consolidated Statements of Financial Position as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. Further, ASU 2015-15 was issued in August 2015 to clarify the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements, whereby an entity may defer debt issuance costs as an asset and subsequently amortize them over the term of the line-of-credit. The accounting updates are effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. Effective January 1, 2016, the Company adopted ASU 2015-03 on a retrospective basis which, as at December 31, 2015, resulted in a decrease in Deferred amounts and other assets of $149 million (2014 - $116 million) and a corresponding decrease in Long-term debt of $149 million (2014 - $116 million).

Amendments to the Consolidation Analysis

ASU 2015-02, issued in February 2015, revises the current consolidation guidance which results in a change in the determination of whether an entity consolidates certain types of legal entities. The new standard is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied on a full or modified retrospective basis. Effective January 1, 2016, the Company adopted ASU 2015-02 on a modified retrospective basis, which amended and clarified the guidance on variable interest entities (VIEs). There was a significant change in the assessment of limited partnerships and other similar legal entities as VIEs, including the removal of the presumption that the general partner should consolidate a limited partnership. As a result, the Company has determined that a majority of the limited partnerships that are currently consolidated or equity accounted for are VIEs. The amended guidance did not impact the Company's accounting treatment of such entities.

Extraordinary and Unusual Items

Effective January 1, 2015, the Company retrospectively adopted ASU 2015-01 which eliminates the concept of extraordinary items from U.S. GAAP. Entities will no longer be required to separately classify and present extraordinary items in the Consolidated Statements of Earnings. There was no material impact to the Company's consolidated financial statements as a result of adopting this update.

Hybrid Financial Instruments Issued in the Form of a Share

ASU 2014-16 was issued in November 2014 with the intent to eliminate the use of different methods in practice in the accounting for hybrid financial instruments issued in the form of a share. The new standard clarifies the evaluation of the economic characteristics and risks of a host contract in these hybrid financial instruments. This accounting update is effective for annual and interim periods beginning after December 15, 2015 and is to be applied on a modified retrospective basis. Effective January 1, 2016, the Company adopted ASU 2014-16 on a modified retrospective basis. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Development Stage Entities

ASU 2014-10, issued in June 2014, amended the consolidation guidance to eliminate the development stage entity relief when applying the VIE model and evaluating the sufficiency of equity at risk. This accounting update is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively. Effective January 1, 2016, the Company adopted ASU 2014-10 on a retrospective basis. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
Effective January 1, 2015, the Company prospectively adopted ASU 2014-08 which changes the criteria and disclosures for reporting discontinued operations. The revised criteria is expected to result in fewer transactions being categorized as discontinued operations. There was no material impact to the consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES
Improvements to Employee Share-Based Payment Accounting
ASU 2016-09 was issued in March 2016 with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the Statements of Cash Flows. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective December 15, 2016.

Simplifying the Equity Method of Accounting
ASU 2016-07 was issued in March 2016 with the intent of simplifying the equity method of accounting by eliminating the requirement to retrospectively apply the equity method to an investment that subsequently qualifies for such accounting as a result of an increase in the level of ownership interest or degree of influence. Consequently, the equity method of accounting will be applied prospectively from the date significant influence is obtained. The cost of acquiring an additional interest in the investee, if any, will be added to the current basis of the previously held interest. For available-for-sale securities that become eligible for the equity method of accounting, any unrealized gain or loss recorded within AOCI will be recognized in earnings at the date the investment initially qualifies for the use of the equity method. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2016, and is to be applied prospectively.

Derivative Contract Novations on Existing Hedge Accounting Relationships
ASU 2016-05 was issued in March 2016 with the intent of clarifying that a change in the counterparty derivative instrument does not require de-designation of that hedge accounting relationship provided that all other hedge accounting criteria continue to be met. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2016 and may be applied on a prospective or modified retrospective basis.

Recognition of Leases
ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the Consolidated Statements of Financial Position and disclosing additional key information about leasing arrangements. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018, and is to be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities
ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the Statements of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively.

Classification of Deferred Taxes on the Statements of Financial Position
ASU 2015-17 was issued in November 2015 with the intent to simplify the presentation of deferred income taxes. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Statements of Financial Position. The accounting update is effective for fiscal years beginning after December 15, 2016 and is to be applied on a prospective or retrospective basis. Early application is permitted for all entities as of the beginning of an interim or annual reporting period. Effective January 1, 2016, the Company elected to early adopt ASU 2015-17 and applied the standard on a prospective basis.

Simplifying the Accounting for Measurement-Period Adjustments in Business Combinations
ASU 2015-16 was issued in September 2015 with the intent to simplify the accounting for measurement-period adjustments in business combinations. The new standard requires that an acquirer must recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The accounting update is effective for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. Effective January 1, 2016, the Company adopted ASU 2015-16 on a prospective basis.

Simplifying the Measurement of Inventory
ASU 2015-11 was issued in July 2015 with the intent to simplify the measurement of inventory. The new standard requires inventory to be measured at the lower of cost and net realizable value and is applicable to all inventory, with the exception of inventory measured using last-in, first-out or the retail inventory method. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim reporting periods beginning after December 15, 2016 and is to be applied on a prospective basis.

Measurement Date of Defined Benefit Obligation and Plan Assets
ASU 2015-04 was issued in April 2015 with the intent to simplify the fair value measurement of defined benefit plan assets and obligations. For entities with a fiscal year end that does not coincide with a month end, the new standard permits an entity to measure its defined benefit plan assets and obligations using the month end that is closest to the entity’s fiscal year end. In addition, where there are significant events in an interim period that would trigger a re-measurement of the plan assets and obligations, an entity is also permitted to re-measure such assets and obligations using the month end that is closest to the date of the significant event. The accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis.

Revenue from Contracts with Customers
ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. In July 2015, the effective date of the new standard was delayed by one year and the new standard is now effective for annual and interim periods beginning on or after December 15, 2017 and may be applied on either a full or modified retrospective basis. ASU 2016-08 was issued in March 2016 with the intent of clarifying the implementation guidance on principal versus agent considerations. Further, ASU 2016-10 was issued in April 2016 to clarify guidance on identifying performance obligations and licensing implementation. The effective dates for the amendments are the same as ASU 2014-09. The Company is currently assessing the impact of the new standards on its consolidated financial statements.

CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and United States securities law. As at December 31, 2015, an evaluation was carried out under the supervision of and with the participation of Enbridge's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operations of Enbridge's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective in ensuring that information required to be disclosed by Enbridge in reports that it files with or submits to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

Management's Report on Internal Control over Financial Reporting

Management of Enbridge is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in the rules of the SEC and the Canadian Securities Administrators. The Company's internal control over financial reporting is a process designed under the supervision and with the participation of executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external reporting purposes in accordance with U.S. GAAP.

The Company's internal control over financial reporting includes policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

The Company's internal control over financial reporting may not prevent or detect all misstatements because of inherent limitations. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with the Company's policies and procedures.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2015, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2015.

During the year ended December 31, 2015, there has been no material change in the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as at December 31, 2015 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company.

ENBRIDGE INC.

AMENDED CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2015

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

Financial Reporting

Management of Enbridge Inc. (the Company) is responsible for the accompanying amended consolidated financial statements and all related financial information contained in this report, including Management's Discussion and Analysis. The amended consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and necessarily include amounts that reflect management's judgment and best estimates.

The Board of Directors (the Board) and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (the AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders. The internal auditors and independent auditors have unrestricted access to the AF&RC.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with U.S. GAAP and provide reasonable assurance that assets are safeguarded.

Management assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2015, based on the framework established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2015.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the amended consolidated financial statements of the Company and its internal control over financial reporting in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) and have issued an unqualified audit report, which is accompanying the amended consolidated financial statements.

"signed"

Al Monaco
President & Chief Executive Officer

"signed"

John K. Whelen
Executive Vice President &
Chief Financial Officer

May 12, 2016

Independent Auditor's Report

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2015 and 2014 amended consolidated financial statements and its internal control over financial reporting as at December 31, 2015. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements

We have audited the accompanying amended consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the two years in the period ended December 31, 2015, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these amended consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these amended consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the amended consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the amended consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the amended consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the amended consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the amended consolidated financial statements.

Opinion
In our opinion, the amended consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31, 2015 and December 31, 2014 and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2015 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of matter
We draw attention to Note 2 to the amended consolidated financial statements, which describes the revision and reissuance of the financial statements due to the effects of changes in Enbridge Inc.'s reportable segments, removal of the 2013 comparative period, adoption of new accounting standards and updates to subsequent events disclosure. We issued our original auditor's report dated February 19, 2016 on the previously issued consolidated financial statements. Due to the revisions described in Note 2, we provide this amended auditor's report on the amended consolidated financial statements. Our audit procedures on subsequent events after February 19, 2016 are restricted solely to the amendment of the consolidated financial statements.

Report on internal control over financial reporting
We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Management's responsibility for internal control over financial reporting
Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying management's report on internal control over financial reporting.

Auditor's responsibility
Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on the company's internal control over financial reporting.

Definition of internal control over financial reporting
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal

control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent limitations
Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion
In our opinion, Enbridge Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta
February 19, 2016, except with respect to our opinion on the amended consolidated financial statements insofar as it relates to revisions described in Note 2, as to which the date is May 12, 2016

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2015**	2014
(millions of Canadian dollars, except per share amounts)		
Revenues		
Commodity sales	**23,842**	28,281
Gas distribution sales	**3,096**	2,853
Transportation and other services	**6,856**	6,507
	33,794	37,641
Expenses		
Commodity costs	**22,949**	27,504
Gas distribution costs	**2,292**	1,979
Operating and administrative	**4,248**	3,281
Depreciation and amortization	**2,024**	1,577
Environmental costs, net of recoveries	**(21)**	100
Goodwill impairment *(Note 15)*	**440**	-
	31,932	34,441
	1,862	3,200
Income from equity investments *(Note 11)*	**475**	368
Other expense *(Note 27)*	**(702)**	(266)
Interest expense *(Note 17)*	**(1,624)**	(1,129)
	11	2,173
Income taxes *(Note 25)*	**(170)**	(611)
Earnings/(loss) from continuing operations	**(159)**	1,562
Discontinued operations *(Note 9)*		
Earnings from discontinued operations before income taxes	**-**	73
Income taxes from discontinued operations	**-**	(27)
Earnings from discontinued operations	**-**	46
Earnings/(loss)	**(159)**	1,608
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**410**	(203)
Earnings attributable to Enbridge Inc.	**251**	1,405
Preference share dividends	**(288)**	(251)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**(37)**	1,154
Earnings/(loss) attributable to Enbridge Inc. common shareholders		
Earnings/(loss) from continuing operations	**(37)**	1,108
Earnings from discontinued operations, net of tax	**-**	46
	(37)	1,154
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 21)*		
Continuing operations	**(0.04)**	1.34
Discontinued operations	**-**	0.05
	(0.04)	1.39
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 21)*		
Continuing operations	**(0.04)**	1.32
Discontinued operations	**-**	0.05
	(0.04)	1.37

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Earnings/(loss)	**(159)**	1,608
Other comprehensive income/(loss), net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**198**	(833)
Change in unrealized loss on net investment hedges	**(903)**	(270)
Other comprehensive income from equity investees	**30**	10
Reclassification to earnings of realized cash flow hedges	**(191)**	76
Reclassification to earnings of unrealized cash flow hedges	**(121)**	158
Reclassification to earnings of pension plans and other postretirement benefits amortization amounts	**21**	15
Actuarial gains/(loss) on pension plans and other postretirement benefits	**51**	(191)
Change in foreign currency translation adjustment	**3,347**	1,238
Reclassification to earnings of derecognized cash flow hedges *(Note 24)*	**(247)**	-
Other comprehensive income	**2,185**	203
Comprehensive income	**2,026**	1,811
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**292**	(242)
Comprehensive income attributable to Enbridge Inc.	**2,318**	1,569
Preference share dividends	**(288)**	(251)
Comprehensive income attributable to Enbridge Inc. common shareholders	**2,030**	1,318

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	**2015**	2014
(millions of Canadian dollars, except per share amounts)		
Preference shares *(Note 21)*		
Balance at beginning of year	**6,515**	5,141
Preference shares issued	**-**	1,374
Balance at end of year	**6,515**	6,515
Common shares *(Note 21)*		
Balance at beginning of year	**6,669**	5,744
Common shares issued	**-**	446
Dividend reinvestment and share purchase plan	**646**	428
Shares issued on exercise of stock options	**76**	51
Balance at end of year	**7,391**	6,669
Additional paid-in capital		
Balance at beginning of year	**2,549**	746
Stock-based compensation	**35**	31
Options exercised	**(19)**	(14)
Issuance of treasury stock	**-**	22
Drop down of interest to Enbridge Energy Partners, L.P. *(Note 20)*	**218**	-
Enbridge Energy Partners, L.P. equity restructuring *(Note 20)*	**-**	1,601
Transfer of interest to Enbridge Income Fund	**-**	176
Drop down of interest to Midcoast Energy Partners, L.P.	**-**	(18)
Dilution gain on Enbridge Income Fund issuance of trust units *(Note 20)*	**355**	-
Dilution gain on Enbridge Income Fund equity investment *(Note 20)*	**132**	-
Dilution loss on Enbridge Income Fund indirect equity investment *(Note 20)*	**(5)**	-
Dilution gains and other	**36**	5
Balance at end of year	**3,301**	2,549
Retained earnings		
Balance at beginning of year	**1,571**	2,550
Earnings attributable to Enbridge Inc.	**251**	1,405
Preference share dividends	**(288)**	(251)
Common share dividends declared	**(1,596)**	(1,177)
Dividends paid to reciprocal shareholder	**22**	17
Reversal of cumulative redemption value adjustment attributable to Enbridge Commercial Trust *(Note 20)*	**541**	-
Redemption value adjustment attributable to redeemable noncontrolling interests *(Note 20)*	**(359)**	(973)
Balance at end of year	**142**	1,571
Accumulated other comprehensive income/(loss) *(Note 23)*		
Balance at beginning of year	**(435)**	(599)
Other comprehensive income attributable to Enbridge Inc. common shareholders	**2,067**	164
Balance at end of year	**1,632**	(435)
Reciprocal shareholding		
Balance at beginning of year	**(83)**	(86)
Issuance of treasury stock	**-**	3
Balance at end of year	**(83)**	(83)
Total Enbridge Inc. shareholders' equity	**18,898**	16,786
Noncontrolling interests *(Note 20)*		
Balance at beginning of year	**2,015**	4,014
Earnings/(loss) attributable to noncontrolling interests	**(407)**	214
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**161**	(192)
Change in foreign currency translation adjustment	**273**	146
Reclassification to earnings of realized cash flow hedges	**(236)**	18
Reclassification to earnings of unrealized cash flow hedges	**(83)**	77
	115	49
Comprehensive income/(loss) attributable to noncontrolling interests	**(292)**	263
Distributions *(Note 20)*	**(680)**	(535)
Contributions *(Note 20)*	**615**	212
Dilution loss	**(53)**	-
Acquisitions - Magic Valley and Wildcat wind farms *(Note 6)*	**-**	351
Drop down of interest to Enbridge Energy Partners, L.P. *(Note 20)*	**(304)**	-
Enbridge Energy Partners, L.P. equity restructuring *(Note 20)*	**-**	(2,330)
Drop down of interest to Midcoast Energy Partners, L.P. *(Note 20)*	**-**	39
Other	**(1)**	1
Balance at end of year	**1,300**	2,015
Total equity	**20,198**	18,801
Dividends paid per common share	**1.86**	1.40

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	2015	2014
(millions of Canadian dollars)		
Operating activities		
Earnings/(loss)	**(159)**	1,608
Earnings from discontinued operations	**-**	(46)
Depreciation and amortization	**2,024**	1,577
Deferred income taxes *(Note 25)*	**7**	587
Changes in unrealized (gains)/loss on derivative instruments, net	**2,373**	(96)
Cash distributions in excess of equity earnings	**244**	196
Impairment *(Notes 9 and 15)*	**536**	18
Gains on dispositions *(Notes 6 and 27)*	**(94)**	(38)
Hedge ineffectiveness	**(20)**	210
Inventory revaluation allowance	**410**	174
Other	**(62)**	115
Changes in regulatory assets and liabilities	**41**	22
Changes in environmental liabilities, net of recoveries	**(43)**	(78)
Changes in operating assets and liabilities *(Note 29)*	**(686)**	(1,721)
Cash provided by continuing operations	**4,571**	2,528
Cash provided by discontinued operations *(Note 9)*	**-**	19
	4,571	2,547
Investing activities		
Additions to property, plant and equipment	**(7,273)**	(10,524)
Long-term investments	**(622)**	(854)
Restricted long-term investments *(Note 12)*	**(49)**	-
Additions to intangible assets	**(101)**	(208)
Acquisitions	**(106)**	(394)
Proceeds from disposition	**146**	85
Affiliate loans, net	**59**	13
Changes in restricted cash	**13**	(13)
Cash used in continuing operations	**(7,933)**	(11,895)
Cash provided by discontinued operations *(Note 9)*	**-**	4
	(7,933)	(11,891)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**(588)**	734
Net change in commercial paper and credit facility draws	**1,507**	4,212
Southern Lights project financing repayments	**-**	(1,519)
Debenture and term note issues - Southern Lights	**-**	1,507
Debenture and term note issues	**3,767**	5,414
Debenture and term note repayments	**(1,023)**	(1,348)
Contributions from noncontrolling interests	**615**	212
Distributions to noncontrolling interests	**(680)**	(535)
Contributions from redeemable noncontrolling interests	**670**	323
Distributions to redeemable noncontrolling interests	**(114)**	(79)
Preference shares issued	**-**	1,365
Common shares issued	**57**	478
Preference share dividends	**(288)**	(245)
Common share dividends	**(950)**	(749)
	2,973	9,770
Effect of translation of foreign denominated cash and cash equivalents	**143**	59
Increase/(decrease) in cash and cash equivalents	**(246)**	485
Cash and cash equivalents at beginning of year - continuing operations	**1,261**	756
Cash and cash equivalents at beginning of year - discontinued operations	**-**	20
Cash and cash equivalents at end of year	**1,015**	1,261
Cash and cash equivalents - discontinued operations	**-**	-
Cash and cash equivalents - continuing operations	**1,015**	1,261
Supplementary cash flow information		
Income taxes paid	**80**	9
Interest paid	**1,835**	1,435

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2015**	2014
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,015**	1,261
Restricted cash	**34**	47
Accounts receivable and other *(Note 7)*	**5,430**	5,504
Accounts receivable from affiliates	**7**	241
Inventory *(Note 8)*	**1,111**	1,148
	7,597	8,201
Property, plant and equipment, net *(Note 9)*	**64,434**	53,830
Long-term investments *(Note 11)*	**7,008**	5,408
Restricted long-term investments *(Note 12)*	**49**	-
Deferred amounts and other assets *(Note 13)*	**3,160**	3,092
Intangible assets, net *(Note 14)*	**1,348**	1,166
Goodwill *(Note 15)*	**80**	483
Deferred income taxes *(Note 25)*	**839**	561
	84,515	72,741
Liabilities and equity		
Current liabilities		
Bank indebtedness	**361**	507
Short-term borrowings *(Note 17)*	**599**	1,041
Accounts payable and other *(Note 16)*	**7,351**	6,444
Accounts payable to affiliates	**48**	80
Interest payable	**324**	264
Environmental liabilities	**141**	161
Current maturities of long-term debt *(Note 17)*	**1,990**	1,004
	10,814	9,501
Long-term debt *(Note 17)*	**39,391**	33,307
Other long-term liabilities *(Note 18)*	**6,056**	4,041
Deferred income taxes *(Note 25)*	**5,915**	4,842
	62,176	51,691
Commitments and contingencies *(Note 31)*		
Redeemable noncontrolling interests *(Note 20)*	**2,141**	2,249
Equity		
Share capital *(Note 21)*		
Preference shares	**6,515**	6,515
Common shares (868 and 852 outstanding at December 31, 2015 and 2014, respectively)	**7,391**	6,669
Additional paid-in capital	**3,301**	2,549
Retained earnings	**142**	1,571
Accumulated other comprehensive income/(loss) *(Note 23)*	**1,632**	(435)
Reciprocal shareholding	**(83)**	(83)
Total Enbridge Inc. shareholders' equity	**18,898**	16,786
Noncontrolling interests *(Note 20)*	**1,300**	2,015
	20,198	18,801
	84,515	72,741

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

"signed"
David A. Arledge
Chair

"signed"
J. Herb England
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Inc. (Enbridge or the Company) is a publicly traded energy transportation and distribution company. Enbridge conducts its business through five business segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services. These operating segments are strategic business units established by senior management to facilitate the achievement of the Company's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States, including Canadian Mainline, Lakehead Pipeline System (Lakehead System), Regional Oil Sands System, Mid-Continent and Gulf Coast, Southern Lights Pipeline, Bakken System and Feeder Pipelines and Other.

GAS DISTRIBUTION

Gas Distribution consists of the Company's natural gas utility operations, the core of which is Enbridge Gas Distribution Inc. (EGD), which serves residential, commercial and industrial customers, primarily in central and eastern Ontario as well as northern New York State. This business segment also includes natural gas distribution activities in Quebec and New Brunswick and the Company's investment in Noverco Inc. (Noverco).

GAS PIPELINES AND PROCESSING

Gas Pipelines and Processing consists of investments in natural gas pipelines and gathering and processing facilities. Investments in natural gas pipelines include the Company's interests in the Alliance Pipeline, the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas extraction and fractionation business located near the terminus of the Alliance Pipeline, Canadian Midstream assets located in northeast British Columbia and northwest Alberta and United States Midstream assets located primarily in Texas and Oklahoma.

GREEN POWER AND TRANSMISSION

Green Power and Transmission consists of the Company's investments in renewable energy assets and transmission facilities. Renewable energy assets consist of wind, solar, geothermal and waste heat recovery facilities and are located in Canada primarily in the provinces of Alberta, Ontario and Quebec and in the United States primarily in Colorado, Texas and Indiana.

ENERGY SERVICES

The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage the Company's volume commitments on the Alliance Pipeline, Vector and other pipeline systems.

ELIMINATIONS AND OTHER

In addition, Eliminations and Other includes operating and administrative costs and foreign exchange costs which are not allocated to business segments. Also included in Eliminations and Other are new business development activities, general corporate investments and elimination of transactions between segments required to present financial performance and financial position on a consolidated basis.

CANADIAN RESTRUCTURING PLAN

Effective September 1, 2015, under an agreement with Enbridge Income Fund (the Fund) and Enbridge Income Fund Holdings Inc. (ENF), Enbridge transferred its Canadian Liquids Pipelines business, held by Enbridge Pipelines Inc. (EPI) and Enbridge Pipelines (Athabasca) Inc. (EPAI), and certain Canadian renewable energy assets to the Fund Group (comprising the Fund, Enbridge Commercial Trust (ECT), Enbridge Income Partners LP (EIPLP) and the subsidiaries of EIPLP) for consideration valued at $30.4

billion plus incentive distribution and performance rights (the Canadian Restructuring Plan). The consideration that Enbridge received included $18.7 billion of units in the Fund Group, comprised of $3 billion of Fund units and $15.7 billion of equity units of EIPLP, in which the Fund has an interest. The Fund Group also assumed debt of EPI and EPAI of approximately $11.7 billion. Upon closing of the transaction, Enbridge's overall economic interest in the Fund Group increased to 91.9% (overall economic interest prior to the transfer was 66.4%).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted. As a Securities and Exchange Commission registrant, the Company is permitted to use U.S. GAAP for purposes of meeting both its Canadian and United States continuous disclosure requirements.

REVISION OF CONSOLIDATED FINANCIAL STATEMENTS

Segmented Information

Effective January 1, 2016, as a result of the recent changes from the Canadian Restructuring Plan, Enbridge revised its reportable segments to better reflect the underlying operations of the Company. The Company believes this new format more clearly describes the financial performance of its business segments, provides increased transparency with respect to operational results and aligns with business segment decision making and management.

The Company is filing these consolidated financial statements to retrospectively apply the revisions to its reportable segments to the annual consolidated financial statements of the Company that was previously filed on February 19, 2016. Revisions to the segmented information presentation include:

- The replacement of the previous segments: Liquids Pipelines; Gas Distribution; Gas Pipelines, Processing and Energy Services; Sponsored Investments; and Corporate with new segments: Liquids Pipelines; Gas Distribution; Gas Pipelines and Processing; Green Power and Transmission; and Energy Services;
- Presenting the Earnings before interest and income taxes of each segment as opposed to Earnings attributable to Enbridge Inc. common shareholders. Amounts related to Interest expense, Income taxes, Earnings attributable to noncontrolling interests and redeemable noncontrolling interests and Preference share dividends are now reported on a consolidated basis.

This retrospective revision resulted in the following note disclosures being revised:

- Note 1 General Business Description;
- Note 2 Summary of Significant Accounting Policies;
- Note 4 Segmented Information;
- Note 5 Financial Statement Effects of Rate Regulation;
- Note 6 Acquisitions and Dispositions;
- Note 9 Property, Plant and Equipment;
- Note 10 Variable Interest Entities;
- Note 11 Long-Term Investments;
- Note 15 Goodwill;
- Note 17 Debt;
- Note 28 Severance Costs;
- Note 30 Related Party Transactions; and
- Note 31 Commitments and Contingencies

These changes had no impact on reported consolidated earnings.

Other Retrospective Revisions

Debt Issuance Costs

As disclosed in Note 3 Changes in Accounting Policies, effective January 1, 2016 the Company retrospectively adopted Accounting Standard Update (ASU) 2015-03. As a result, these consolidated financial statements reflect a retrospective revision related to the reclassification of deferred financing costs from Deferred amounts and other assets to Long-term debt. This retrospective revision resulted in the Statements of Financial Position and Note 13 Deferred Amounts and Other Assets being revised.

Comparative Amounts

The 2013 comparative period has been omitted for presentation purposes as it is not required under U.S. GAAP or applicable securities regulations.

Other

For the purposes of filing these consolidated financial statements, Note 3 Changes in Accounting Policies and Note 33 Subsequent Events have been updated to the date of filing.

Other than the above, no other changes have been made to these consolidated financial statements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 5)*; unbilled revenues *(Note 7)*; allowance for doubtful accounts *(Note 7)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; amortization rates of intangible assets *(Note 14)*; measurement of goodwill *(Note 15)*; fair value of asset retirement obligations (ARO) *(Note 19)*; valuation of stock-based compensation *(Note 22)*; fair value of financial instruments *(Note 24)*; provisions for income taxes *(Note 25)*; assumptions used to measure retirement and other postretirement benefit obligations (OPEB) *(Note 26)*; commitments and contingencies *(Note 31)*; and estimates of losses related to environmental remediation obligations *(Note 31)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Enbridge, its subsidiaries and variable interest entities (VIEs) for which the Company is the primary beneficiary. Upon inception of a contractual agreement, the Company performs an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. Where the Company concludes it is the primary beneficiary of a VIE, the Company will consolidate the accounts of that entity. The consolidated financial statements also include the accounts of any limited partnerships where the Company represents the general partner and, based on all facts and circumstances, controls such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where the Company retains an undivided interest in assets and liabilities, Enbridge records its proportionate share of assets, liabilities, revenues and expenses.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests and redeemable noncontrolling interests. Investments and entities over which the Company exercises significant influence are accounted for using the equity method.

As a result of the Canadian Restructuring Plan, ECT, a subsidiary of the Company, determines its equity investment earnings from EIPLP using the Hypothetical Liquidation at Book Value (HLBV) method. ECT applies the HLBV method to its equity method investments where cash distributions, including both preference and residual distributions, are not based on the investor’s ownership percentages. Under the HLBV method, a calculation is prepared at each balance sheet date to determine the amount that ECT would receive if EIPLP were to liquidate all of its assets, as valued in accordance with U.S. GAAP, and distribute that cash to the investors. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period, after adjusting for capital contributions and distributions, is ECT's share of the earnings or losses from the equity investment for the period.

While ECT and EIPLP are both consolidated in these financial statements, the use of the HLBV method by ECT impacts the earnings attributable to redeemable noncontrolling interests reported on Enbridge's Consolidated Statements of Earnings. The Company continues to recognize Redeemable noncontrolling interests on the Consolidated Statements of Financial Position at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares.

REGULATION

Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for non rate-regulated entities.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the NEB's Land Matters Consultation Initiative (LMCI). Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, the Company would capitalize interest using a capitalization rate based on its cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

For certain regulated operations to which U.S. GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with U.S. GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with U.S. GAAP and no deferred regulatory asset is recorded *(Note 5)*.

With the approval of the regulator, EGD and certain distribution operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from the Company's expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION

For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer credit worthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain revenues from liquids and gas pipeline businesses are recognized under the terms of committed delivery contracts rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts rateably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. The Company recognizes revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Certain offshore pipeline transportation contracts require the Company to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay the Company a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized rateably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Since July 1, 2011 onward, Canadian Mainline (excluding Lines 8 and 9) earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective on that date, the Company prospectively discontinued the application of rate-regulated accounting for those assets with the exception of flow-through income taxes covered by a specific rate order.

For natural gas utility rate-regulated operations in Gas Distribution, revenues are recognized in a manner consistent with the underlying rate-setting mechanism as mandated by the regulator. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company’s distribution franchise area.

For natural gas and marketing businesses, an estimate of revenues and commodity costs for the month of December is included in the Consolidated Statements of Earnings for each year based on the best available volume and price data for the commodity delivered and received.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item’s effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges.

Cash Flow Hedges

The Company uses cash flow hedges to manage its exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to its share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges

The Company may use fair value hedges to hedge the fair value of debt instruments or commodity positions. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

Gains and losses arising from translation of net investment in foreign operations from their functional currencies to the Company's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA). The Company designates foreign currency derivatives and United States dollar denominated debt as hedges of net investments in United States dollar denominated foreign operations. As a result, the effective portion of the change in the fair value of the foreign currency derivatives as well as the translation of United States dollar denominated debt are reflected in OCI and any ineffectiveness is reflected in current period earnings. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from disposal of a foreign operation.

Classification of Derivatives

The Company recognizes the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily from the issuance of debt and accounts for these costs as a deduction from Long-term debt on the Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

EQUITY INVESTMENTS
Equity investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, the Company capitalizes interest costs associated with its investment during such period.

RESTRICTED LONG-TERM INVESTMENTS
Long-term investments that are restricted as to withdrawal or usage, for the purposes of the NEB's LMCI, are presented as Restricted long-term investments on the Consolidated Statements of Financial Position.

OTHER INVESTMENTS
Generally, the Company classifies equity investments in entities over which it does not exercise significant influence and that do not trade on an actively quoted market as other investments carried at cost. Financial assets in this category are initially recorded at fair value with no subsequent re-measurement. Any investments which do trade on an active market are classified as available for sale investments measured at fair value through OCI. Dividends received from investments carried at cost are recognized in earnings when the right to receive payment is established.

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and VIEs. The portion of equity not owned by the Company in such entities is reflected as noncontrolling interests within the equity section of the Consolidated Statements of Financial Position and, in the case of redeemable noncontrolling interests, within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

The Fund's noncontrolling interest holders have the option to redeem the Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interests are recognized at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares. On a quarterly basis, changes in estimated redemption values are reflected as a charge or credit to retained earnings.

The use of the HLBV method by ECT impacts the earnings attributable to redeemable noncontrolling interests reported on Enbridge's Consolidated Statements of Earnings.

INCOME TAXES
The liability method of accounting for income taxes is followed. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Company's regulated operations, a deferred income tax liability is recognized with a corresponding regulatory asset to the extent taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect on the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH

Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific commercial arrangements, are presented as Restricted cash on the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES

Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

INVENTORY

Inventory is comprised of natural gas in storage held in EGD and crude oil and natural gas held primarily by energy services businesses in the Energy Services segment. Natural gas in storage in EGD is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other commodities inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs on the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Company capitalizes interest incurred during construction for non rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets primarily include: costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; contractual receivables under the terms of long-term delivery contracts; and derivative financial instruments.

INTANGIBLE ASSETS
Intangible assets consist primarily of certain software costs, natural gas supply opportunities, acquired power purchase agreements, land leases and permits. The Company capitalizes costs incurred during the application development stage of internal use software projects. Natural gas supply opportunities are growth opportunities, identified upon acquisition, present in gas producing zones where certain United States gas systems are located. Intangible assets are amortized on a straight-line basis over their expected lives, commencing when the asset is available for use.

GOODWILL
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. The Company has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step involves determining the fair value of the Company's reporting units inclusive of goodwill and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the reporting unit's assets and liabilities.

IMPAIRMENT
The Company reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to investments in debt and equity securities, the Company assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Company internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, the Company assesses the assets for impairment when it no longer has reasonable assurance of timely collection. If evidence of impairment is noted, the Company reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

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

For the majority of the Company's assets, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

RETIREMENT AND POSTRETIREMENT BENEFITS

The Company maintains pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. In 2014, new mortality tables were issued by the Society of Actuaries in the United States which were further revised in 2015. These tables, along with the Canadian Institute of Actuaries tables that were revised in 2013, were used by the Company for measurement of its benefit obligations of its United States pension plan (the United States Plan) and the Canadian pension plans (the Canadian Plans), respectively. The Company determines discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments the Company anticipates making under each of the respective plans. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;
- Amortization of the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by the Company are expensed in the period in which the contribution occurs.

The Company also provides OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets, Accounts payable and other or Other long-term liabilities, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

Certain regulated utility operations of the Company record regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

STOCK-BASED COMPENSATION
Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance stock options (PSO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the PSO granted as calculated by the Bloomberg barrier option valuation model and is recognized over the vesting period with a corresponding credit to Additional paid-in capital. The options become exercisable when both performance targets and time vesting requirements have been met. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Performance Stock Units (PSU) and Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. PSU vest at the completion of a three-year term and RSU vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of the Company’s shares with an offset to Accounts payable and other or to Other long-term liabilities. The value of the PSU is also dependent on the Company’s performance relative to performance targets set out under the plan.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES
The Company expenses or capitalizes, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. The Company expenses costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. The Company records liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies’ clean-up experience and data released by government organizations. The Company’s estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. The Company evaluates recoveries from insurance coverage separately from the liability and, when recovery is probable, the Company records and reports an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analysing available information, the Company determines it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Company recognizes the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. The Company expenses legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Simplifying the Presentation of Debt Issuance Costs

ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires debt issuance costs related to a recognized debt liability to be presented in the Consolidated Statements of Financial Position as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. Further, ASU 2015-15 was issued in August 2015 to clarify the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements, whereby an entity may defer debt issuance costs as an asset and subsequently amortize them over the term of the line-of-credit. The accounting updates are effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. Effective January 1, 2016, the Company adopted ASU 2015-03 on a retrospective basis which, as at December 31, 2015, resulted in a decrease in Deferred amounts and other assets of $149 million (2014 - $116 million) and a corresponding decrease in Long-term debt of $149 million (2014 - $116 million).

Amendments to the Consolidation Analysis

ASU 2015-02, issued in February 2015, revises the current consolidation guidance which results in a change in the determination of whether an entity consolidates certain types of legal entities. The new standard is effective for annual and interim reporting periods beginning after December 15, 2015 and may be applied on a full or modified retrospective basis. Effective January 1, 2016, the Company adopted ASU 2015-02 on a modified retrospective basis, which amended and clarified the guidance on VIEs. There was a significant change in the assessment of limited partnerships and other similar legal entities as VIEs, including the removal of the presumption that the general partner should consolidate a limited partnership. As a result, the Company has determined that a majority of the limited partnerships that are currently consolidated or equity accounted for are VIEs. The amended guidance did not impact the Company’s accounting treatment of such entities.

Extraordinary and Unusual Items

Effective January 1, 2015, the Company retrospectively adopted ASU 2015-01 which eliminates the concept of extraordinary items from U.S. GAAP. Entities will no longer be required to separately classify and present extraordinary items in the Consolidated Statements of Earnings. There was no material impact to the Company’s consolidated financial statements as a result of adopting this update.

Hybrid Financial Instruments Issued in the Form of a Share

ASU 2014-16 was issued in November 2014 with the intent to eliminate the use of different methods in practice in the accounting for hybrid financial instruments issued in the form of a share. The new standard clarifies the evaluation of the economic characteristics and risks of a host contract in these hybrid financial instruments. This accounting update is effective for annual and interim periods beginning after December 15, 2015 and is to be applied on a modified retrospective basis. Effective January 1, 2016, the Company adopted ASU 2014-16 on a modified retrospective basis. The adoption of the pronouncement did not have a material impact on the Company’s consolidated financial statements.

Development Stage Entities

ASU 2014-10, issued in June 2014, amended the consolidation guidance to eliminate the development stage entity relief when applying the VIE model and evaluating the sufficiency of equity at risk. This accounting update is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively. Effective January 1, 2016, the Company adopted ASU 2014-10 on a retrospective basis. The adoption of the pronouncement did not have a material impact on the Company’s consolidated financial statements.

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

Effective January 1, 2015, the Company prospectively adopted ASU 2014-08 which changes the criteria and disclosures for reporting discontinued operations. The revised criteria is expected to result in fewer transactions being categorized as discontinued operations. There was no material impact to the consolidated financial statements as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Improvements to Employee Share-Based Payment Accounting

ASU 2016-09 was issued in March 2016 with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the Statements of Cash Flows. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective December 15, 2016.

Simplifying the Equity Method of Accounting

ASU 2016-07 was issued in March 2016 with the intent of simplifying the equity method of accounting by eliminating the requirement to retrospectively apply the equity method to an investment that subsequently qualifies for such accounting as a result of an increase in the level of ownership interest or degree of influence. Consequently, the equity method of accounting will be applied prospectively from the date significant influence is obtained. The cost of acquiring an additional interest in the investee, if any, will be added to the current basis of the previously held interest. For available-for-sale securities that become eligible for the equity method of accounting, any unrealized gain or loss recorded within AOCI will be recognized in earnings at the date the investment initially qualifies for the use of the equity method. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2016, and is to be applied prospectively.

Derivative Contract Novations on Existing Hedge Accounting Relationships

ASU 2016-05 was issued in March 2016 with the intent of clarifying that a change in the counterparty derivative instrument does not require de-designation of that hedge accounting relationship provided that all other hedge accounting criteria continue to be met. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2016 and may be applied on a prospective or modified retrospective basis.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the Consolidated Statements of Financial Position and disclosing additional key information about leasing arrangements. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2018, and is to be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities

ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation, and disclosure of financial assets and liabilities. The amendments revise accounting related to the classification and measurement of investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value, and the disclosure requirements associated with the fair value of financial instruments. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for fiscal years beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the Statements of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively.

Classification of Deferred Taxes on the Statements of Financial Position

ASU 2015-17 was issued in November 2015 with the intent to simplify the presentation of deferred income taxes. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Statements of Financial Position. The accounting update is effective for fiscal years beginning after December 15, 2016 and is to be applied on a prospective or retrospective basis. Early application is permitted for all entities as of the beginning of an interim or annual reporting period. Effective January 1, 2016, the Company elected to early adopt ASU 2015-17 and applied the standard on a prospective basis.

Simplifying the Accounting for Measurement-Period Adjustments in Business Combinations
ASU 2015-16 was issued in September 2015 with the intent to simplify the accounting for measurement-period adjustments in business combinations. The new standard requires that an acquirer must recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The accounting update is effective for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. Effective January 1, 2016, the Company adopted ASU 2015-16 on a prospective basis.

Simplifying the Measurement of Inventory
ASU 2015-11 was issued in July 2015 with the intent to simplify the measurement of inventory. The new standard requires inventory to be measured at the lower of cost and net realizable value and is applicable to all inventory, with the exception of inventory measured using last-in, first-out or the retail inventory method. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The new standard is effective for annual and interim reporting periods beginning after December 15, 2016 and is to be applied on a prospective basis.

Measurement Date of Defined Benefit Obligation and Plan Assets
ASU 2015-04 was issued in April 2015 with the intent to simplify the fair value measurement of defined benefit plan assets and obligations. For entities with a fiscal year end that does not coincide with a month end, the new standard permits an entity to measure its defined benefit plan assets and obligations using the month end that is closest to the entity's fiscal year end. In addition, where there are significant events in an interim period that would trigger a re-measurement of the plan assets and obligations, an entity is also permitted to re-measure such assets and obligations using the month end that is closest to the date of the significant event. The accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 and is to be applied on a prospective basis. Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis.

Revenue from Contracts with Customers
ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. In July 2015, the effective date of the new standard was delayed by one year and the new standard is now effective for annual and interim periods beginning on or after December 15, 2017 and may be applied on either a full or modified retrospective basis. ASU 2016-08 was issued in March 2016 with the intent of clarifying the implementation guidance on principal versus agent considerations. Further, ASU 2016-10 was issued in April 2016 to clarify guidance on identifying performance obligations and licensing implementation. The effective dates for the amendments are the same as ASU 2014-09. The Company is currently assessing the impact of the new standards on its consolidated financial statements.

4. SEGMENTED INFORMATION

Year ended December 31, 2015	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**5,589**	**3,609**	**3,803**	**498**	**20,842**	**(547)**	**33,794**
Commodity and gas distribution costs	**(9)**	**(2,349)**	**(3,002)**	**4**	**(20,443)**	**558**	**(25,241)**
Operating and administrative	**(2,849)**	**(536)**	**(522)**	**(143)**	**(66)**	**(132)**	**(4,248)**
Depreciation and amortization	**(1,227)**	**(308)**	**(272)**	**(186)**	**1**	**(32)**	**(2,024)**
Environmental costs, net of recoveries	**21**	**-**	**-**	**-**	**-**	**-**	**21**
Goodwill impairment	**-**	**-**	**(440)**	**-**	**-**	**-**	**(440)**
	1,525	**416**	**(433)**	**173**	**334**	**(153)**	**1,862**
Income/(loss) from equity investments	**296**	**(10)**	**200**	**2**	**(9)**	**(4)**	**475**
Other income/(expense)	**(15)**	**49**	**4**	**2**	**-**	**(742)**	**(702)**
Earnings/(loss) before interest and income taxes	**1,806**	**455**	**(229)**	**177**	**325**	**(899)**	**1,635**
Interest expense							**(1,624)**
Income taxes							**(170)**
Loss							**(159)**
Loss attributable to noncontrolling interests and redeemable noncontrolling interests							**410**
Preference share dividends							**(288)**
Loss attributable to Enbridge Inc. common shareholders							**(37)**
Additions to property, plant and equipment[1]	**5,884**	**858**	**385**	**68**	**-**	**80**	**7,275**
Total assets	**52,015**	**9,901**	**11,559**	**4,977**	**1,889**	**4,174**	**84,515**

Year ended December 31, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	4,805	3,319	6,650	360	23,099	(592)	37,641
Commodity and gas distribution costs	(1)	(2,082)	(5,686)	3	(22,314)	597	(29,483)
Operating and administrative	(1,985)	(531)	(533)	(94)	(58)	(80)	(3,281)
Depreciation and amortization	(911)	(304)	(221)	(124)	2	(19)	(1,577)
Environmental costs, net of recoveries	(100)	-	-	-	-	-	(100)
	1,808	402	210	145	729	(94)	3,200
Income/(loss) from equity investments	161	(14)	224	3	-	(6)	368
Other income/(expense)	11	44	33	1	1	(356)	(266)
Earnings/(loss) before interest and income taxes	1,980	432	467	149	730	(456)	3,302
Interest expense							(1,129)
Income taxes							(611)
Earnings from continuing operations							1,562
Discontinuing operations							
Earnings from discontinued operations before income taxes							73
Income taxes from discontinued operations							(27)
Earnings from discontinued operations							46
Earnings							1,608
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests							(203)
Preference share dividends							(251)
Earnings attributable to Enbridge Inc. common shareholders							1,154
Additions to property, plant and equipment[1]	8,914	610	593	333	3	74	10,527
Total assets	42,231	9,643	10,423	4,547	1,342	4,555	72,741

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

The measurement basis for preparation of segmented information is consistent with the significant accounting policies *(Note 2)*.

OUT-OF-PERIOD ADJUSTMENT

Earnings attributable to Enbridge Inc. common shareholders for the year ended December 31, 2015 were increased by an out-of-period adjustment of $71 million in respect of an overstatement of deferred income tax expense in 2013 and 2014.

GEOGRAPHIC INFORMATION

Revenues[1]

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Canada	**11,087**	14,963
United States	**22,707**	22,678
	33,794	37,641

1 Revenues are based on the country of origin of the product or service sold.

Property, Plant and Equipment

December 31,	**2015**	2014
(millions of Canadian dollars)		
Canada	**30,656**	27,420
United States	**33,778**	26,410
	64,434	53,830

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS

A number of businesses within the Company are subject to regulation. The Company's significant regulated businesses and related accounting impacts are described below.

Liquids Pipelines

Canadian Mainline

Canadian Mainline includes the Canadian portion of the mainline system and is subject to regulation by the NEB. Canadian Mainline tolls (excluding Lines 8 and 9) are currently governed by the 10-year CTS, which establishes a Canadian Local Toll for all volumes shipped on the Canadian Mainline and an International Joint Tariff for all volumes shipped from western Canadian receipt points to delivery points on the Lakehead System and delivery points on the Canadian Mainline downstream of the Lakehead System. The CTS was negotiated with shippers in accordance with NEB guidelines, was approved by the NEB in June 2011 and took effect July 1, 2011. Under the CTS, a regulatory asset is recognized to offset deferred income taxes as a NEB rate order governing flow-through income tax treatment permits future recovery. No other material regulatory assets or liabilities are recognized under the terms of the CTS.

Southern Lights Pipeline

The United States portion of the Southern Lights Pipeline (Southern Lights US) is regulated by the FERC and the Canadian portion of the Southern Lights Pipeline (Southern Lights Canada) is regulated by the NEB. Shippers on the Southern Lights Pipeline are subject to long-term transportation contracts under a cost of service toll methodology. Toll adjustments are filed annually with the regulators. Tariffs provide for recovery of allowable operating and debt financing costs, plus a pre-determined after-tax rate of return on equity (ROE) of 10%. Southern Lights Pipeline tolls are based on a deemed 70% debt and 30% equity structure.

Gas Distribution

Enbridge Gas Distribution

EGD's gas distribution operations are regulated by the OEB. Rates for the years ended December 31, 2015 and 2014 were set in accordance with parameters established by the customized incentive rate plan (IR Plan). The customized IR Plan was approved in 2014 by the OEB, with modifications, for 2014 through 2018, inclusive of the requested capital investment amounts and an incentive mechanism providing the opportunity to earn above the allowed ROE.

Within annual rate proceedings for 2015 through 2018, the customized IR Plan requires allowed revenues, and corresponding rates, to be updated annually for select items. The OEB also approved the adoption of a new approach for determining net salvage percentages to be included within EGD's approved depreciation rates, as compared with the traditional approach previously employed. The new approach results in lower net salvage percentages for EGD, and therefore lowers depreciation rates and future removal and site restoration reserves. The customized IR Plan includes an earnings sharing mechanism, whereby any return over the allowed rate of return for a given year under the customized IR Plan will be shared equally with customers.

For the year ended December 31, 2013, rates were set pursuant to an OEB approved settlement agreement and decision (the 2013 Settlement) related to its 2013 cost of service rate application. The 2013 Settlement retained the previous deemed equity level but provided for an increase in the allowed ROE. The 2013 Settlement further retained the flow-through nature of the cost of natural gas supply and several other cost categories and provided for OPEB and pension costs, determined on an accrual basis, to be recovered in rates.

EGD's after-tax rate of return on common equity embedded in rates was 9.3% for the year ended December 31, 2015 (2014 - 9.4%) based on a 36% (2014 - 36%) deemed common equity component of capital for regulatory purposes.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick Inc. is regulated by the EUB and currently sets tolls at either market-based or cost of service rates.

FINANCIAL STATEMENT EFFECTS

Accounting for rate-regulated activities has resulted in the recognition of the following significant regulatory assets and liabilities:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory assets/(liabilities)		
Liquids Pipelines		
Deferred income taxes[1]	**1,048**	898
Tolling deferrals[2]	**(39)**	(39)
Recoverable income taxes[3]	**54**	46
Pipeline future abandonment costs[4]	**(47)**	-
Transportation revenue adjustments[5]	**11**	36
Gas Distribution		
Deferred income taxes[6]	**328**	275
Purchased gas variance[7]	**129**	673
Pension plans and OPEB[8]	**104**	171
Constant dollar net salvage adjustment[9]	**42**	37
Unabsorbed demand cost[10]	**66**	14
Future removal and site restoration reserves[11]	**(581)**	(562)
Site restoration clearance adjustment[12]	**(193)**	(283)
Revenue adjustment[13]	**-**	(52)
Transaction services deferral[14]	**(9)**	(26)
Gas Pipelines and Processing		
Deferred income taxes[1]	**-**	24

1 The deferred income tax asset represents the regulatory offset to deferred income tax liabilities that are expected to be recovered under flow-through income tax treatment. The recovery period depends on future reversal of temporary differences.

2 The tolling deferrals reflect net tax benefits expected to be refunded through future transportation tolls on Southern Lights Canada. The balance is expected to continue to accumulate through 2018 before being refunded through tolls. Tolling deferrals are not included in the rate base.

3 *The recoverable income tax asset represents future revenues to be collected from shippers for Southern Lights US to recover federal income taxes payable on the equity component of AFUDC. The recovery period commenced in 2010 and is approximately 30 years.*

4 *The pipeline future abandonment costs liability results from amounts collected and set aside in accordance with the NEB's LMCI to cover future abandonment costs for NEB regulated Canadian pipelines. Funds collected are included in Restricted long-term investments (Note 12). Concurrently, the Company reflects the future abandonment cost as a regulatory liability. The settlement of this balance will occur as pipeline abandonment costs are incurred.*

5 *The transportation revenue adjustments are the cumulative differences between actual expenses incurred and estimated expenses included in transportation tolls. Transportation revenue adjustments are not included in the rate base. The recovery period is approximately five years, commencing with tolls filed and in effect on January 1, 2015, and dependent on shipper throughput levels.*

6 *The deferred income tax asset represents the regulatory offset to deferred income tax liabilities to the extent that deferred income taxes are expected to be recovered or refunded through regulator-approved rates. The recovery period depends on future temporary differences. Deferred income taxes in Gas Distribution are excluded from the rate base and do not earn an ROE.*

7 *The purchased gas variance (PGVA) balance represents the difference between the actual cost and the approved cost of natural gas reflected in rates. EGD has been granted OEB approval to refund this balance to, or to collect this balance from, customers on a rolling 12 month basis via the Quarterly Rate Adjustment Mechanism process. In May 2014, the OEB issued a decision allowing a portion of the PGVA as at June 30, 2014 to be recovered over a 24-month period from July 1, 2014 to June 30, 2016.*

8 *The pension plans and OPEB balances represent the regulatory offset to pension plan and OPEB obligations to the extent the amounts are expected to be collected from customers in future rates. An OPEB balance of $89 million is being collected over a 20-year period that commenced in 2013. The balance at December 31, 2015 was $75 million (2014 - $84 million). The settlement period for the pension regulatory asset is not determinable. The balances are excluded from the rate base and do not earn an ROE.*

9 *The constant dollar net salvage adjustment represents the cumulative variance between the amount proposed for clearance and the actual amount cleared, relating specifically to the Site restoration adjustment. Any residual balance at the end of 2018 will be cleared in a post 2018 true up.*

10 *The unabsorbed demand cost deferral represents the actual cost consequences of unutilized transportation capacity contracted by EGD to meet increased requirements resulting from the Peak Gas Design Day Criteria (PGDDC). EGD updated its PGDDC in 2013 and 2014 and the impact of this update was phased in equally over the two years.*

11 *The future removal and site restoration reserves balance results from amounts collected from customers by certain businesses, with the approval of the regulator, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that has been collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur as future removal and site restoration costs are incurred.*

12 *The site restoration clearance adjustment represents the amount determined by the OEB of previously collected costs for future removal and site restoration that is considered to be in excess of future requirements and will be refunded to customers over the term of the customized IR Plan. This was a result of the OEB's approval of the adoption of a new approach for determining net salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves.*

13 *The revenue adjustment represents the revenue variance between interim rates, which were in place from January 1, 2014 to September 30, 2014, and the final OEB approved 2014 rates, which were implemented on October 1, 2014, but effective January 1, 2014. The revenue adjustment balance is the 2014 OEB approved revenue adjustment amount that was refunded to customers in January 2015.*

14 *The transaction services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. The balance is expected to be refunded to customers in the following year.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Allowance for Funds Used During Construction and Other Capitalized Costs

Under the pool method prescribed by certain regulators, it is not possible to identify the carrying value of the equity component of AFUDC or its effect on depreciation. Similarly, gains and losses on the retirement of certain specific fixed assets in any given year cannot be identified or quantified.

Operating Cost Capitalization

With the approval of regulators, certain operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs would be charged to earnings in the year incurred.

EGD entered into a consulting contract relating to asset management initiatives. The majority of the costs, primarily consulting fees, are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2015, cumulative costs relating to this consulting contract of $179 million (2014 - $166 million) were included in Property, plant and equipment and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

6. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS
Midstream Business
On February 27, 2015, Enbridge Energy Partners, L.P. (EEP) acquired the midstream business of New Gulf Resources, LLC (NGR) in Leon, Madison and Grimes Counties, Texas for $106 million (US$85 million) in cash and a contingent future payment of up to $21 million (US$17 million), through its partially-owned subsidiary, Midcoast Energy Partners, L.P. (MEP). The acquisition consisted of a natural gas gathering system that is in operation and is presented within the Gas Pipelines and Processing segment. Revenues and earnings of $2 million and nil, respectively, since the date of acquisition were recognized for the year ended December 31, 2015.

If the acquisition had occurred on January 1, 2014, changes to revenues and earnings for the years ended December 31, 2015 and 2014 would have been nominal.

The following purchase price allocation was completed by the Company:

February 27,	**2015**
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Property, plant and equipment	**69**
Intangible assets	**40**
	109
Purchase price:	
Cash	**106**
Contingent consideration[1]	**3**

1 *The contingent future payment of up to US$17 million is dependent upon NGR's ability to deliver specified volumes into MEP's system over a five-year period. The fair value of the contingent future consideration at the acquisition date and as at December 31, 2015 was $3 million (US$2 million) and $3 million (US$2 million), respectively.*

Magic Valley and Wildcat Wind Farms ***(Note 10)***
On December 31, 2014, Enbridge acquired an 80% controlling interest in Magic Valley, a wind farm located in Texas, and Wildcat, a wind farm located in Indiana, for cash consideration of $394 million (US$340 million). No revenue or earnings were recognized in the year ended December 31, 2014 as the wind farms were acquired on December 31, 2014. The wind farms are included within the Green Power and Transmission segment.

If the acquisition had occurred on January 1, 2014, proforma consolidated revenues and earnings for the year ended December 31, 2014 would have increased by $64 million (US$58 million) and $8 million (US$7 million), respectively.

The Company has completed its valuation of the acquired assets resulting in the following purchase price allocation.

December 31,	2014
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Property, plant and equipment	747
Intangible assets	12
Other long-term liabilities	(14)
Noncontrolling interests[1] *(Note 20)*	(351)
	394
Purchase price:	
Cash	394

1 *The fair value of the noncontrolling interests was determined using a combination of the implied purchase price for the remaining 20% interest and discounted cash flow models.*

OTHER ACQUISITIONS

In November 2015, the Company acquired a 100% interest in the 103-megawatt (MW) New Creek Wind Project (New Creek) for cash consideration of $48 million (US$36 million), with $35 million (US$26 million) of the purchase price allocated to Property, plant and equipment and the remainder allocated to Intangible assets. New Creek is targeted to be in service in December 2016.

In December 2014, the Company acquired an incremental 30% interest in the Massif du Sud Wind Project (Massif du Sud) for cash consideration of $102 million, bringing its total interest in the wind project to 80%. The Company acquired its original 50% interest in Massif du Sud in December 2012. The Company's interest in Massif du Sud represents an undivided interest, with $97 million of the incremental purchase allocated to Property, plant and equipment and the remainder allocated to Intangible assets. Massif du Sud is operational.

In October 2014, the Company acquired an incremental 17.5% interest in the Lac Alfred Wind Project (Lac Alfred) for cash consideration of $121 million, bringing its total interest in the wind project to 67.5%. The Company acquired its original 50% interest in Lac Alfred in December 2011. The Company's interest in Lac Alfred represents an undivided interest, with $115 million of the incremental purchase allocated to Property, plant and equipment and the remainder allocated to Intangible assets. Lac Alfred is operational.

The New Creek, Massif du Sud and Lac Alfred wind projects are included within the Green Power and Transmission segment.

OTHER DISPOSITIONS

In August 2015, the Company sold its 77.8% controlling interest in the Frontier Pipeline Company, which holds pipeline assets located in the midwest United States, to unrelated parties for gross proceeds of $112 million (US$85 million). A gain of $70 million (US$53 million) was presented within Other expense on the Consolidated Statements of Earnings. These amounts are included within the Liquids Pipelines segment.

In May 2015, the Fund sold certain of its crude oil pipeline system assets within the Liquids Pipelines segment to an unrelated party for gross proceeds of $26 million. A gain of $22 million was presented within Other expense on the Consolidated Statements of Earnings.

In November 2014, the Company sold one of its non-core assets within Enbridge Offshore Pipelines (Offshore), which include pipeline facilities located in Louisiana, to an unrelated party for $7 million (US$7 million). A gain of $22 million (US$19 million) was presented within Other expense on the Consolidated Statements of Earnings. These assets were included within the Gas Pipelines and Processing segment.

In July 2014, the Company sold a 35% equity interest in the Southern Access Extension Project within the Liquids Pipelines segment, a pipeline project then under construction, to an unrelated party for gross proceeds of $73 million (US$68 million). As the fair value of the consideration received equalled the carrying value of the asset sold, no gain or loss was recognized on the sale *(Note 11).*

In March 2014, the Company sold an Alternative and Emerging Technologies investment within Eliminations and Other to an unrelated party for $19 million. A gain of $16 million was presented within Other expense on the Consolidated Statements of Earnings.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Unbilled revenues	**2,476**	2,218
Trade receivables	**1,079**	1,168
Taxes receivable	**175**	522
Regulatory assets	**216**	567
Short-term portion of derivative assets *(Note 24)*	**791**	568
Prepaid expenses and deposits	**181**	103
Current deferred income taxes *(Note 25)*	**367**	245
Dividends receivable	**26**	26
Other	**164**	129
Allowance for doubtful accounts	**(45)**	(42)
	5,430	5,504

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain of EEP's subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis through to December 2016, provided accumulated purchases net of collections do not exceed US$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US$317 million ($439 million) and US$378 million ($439 million) as at December 31, 2015 and 2014, respectively.

8. INVENTORY

December 31,	**2015**	2014
(millions of Canadian dollars)		
Natural gas	**627**	678
Crude oil	**477**	452
Other commodities	**7**	18
	1,111	1,148

9. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2015	2014
(millions of Canadian dollars)			
Liquids Pipelines[1]			
Pipeline	2.7%	**31,092**	22,007
Pumping equipment, buildings, tanks and other	3.1%	**14,319**	12,230
Land and right-of-way	2.4%	**1,221**	1,077
Under construction	-	**6,002**	7,449
		52,634	42,763
Accumulated depreciation		**(8,233)**	(6,655)
		44,401	36,108
Gas Distribution			
Gas mains, services and other	3.0%	**8,819**	8,427
Land and right-of-way	1.0%	**85**	84
Under construction	-	**902**	352
		9,806	8,863
Accumulated depreciation		**(2,379)**	(2,256)
		7,427	6,607
Gas Pipelines and Processing			
Pipeline	2.7%	**3,557**	2,888
Compressors, meters and other operating equipment	3.4%	**3,864**	2,957
Processing and treating plants	2.5%	**869**	599
Pumping equipment, buildings, tanks and other	5.0%	**275**	246
Land and right-of-way	2.3%	**680**	511
Under construction	-	**956**	1,204
		10,201	8,405
Accumulated depreciation		**(2,003)**	(1,505)
		8,198	6,900
Green Power and Transmission			
Wind turbines, solar panels and other	4.1%	**4,311**	3,829
Power transmission	1.8%	**387**	368
Land and right-of-way	4.2%	**45**	28
Under construction	-	**51**	210
		4,794	4,435
Accumulated depreciation		**(600)**	(404)
		4,194	4,031
Energy Services			
Pumping equipment and other	3.4%	**34**	26
Under construction	-	**-**	5
		34	31
Accumulated depreciation		**(13)**	(9)
		21	22
Eliminations and Other			
Vehicles, office furniture, equipment and other	6.1%	**331**	306
		331	306
Accumulated depreciation		**(138)**	(144)
		193	162
		64,434	53,830

1 *In July 2014, $62 million of Property, plant and equipment was disposed as part of the sale of a 35% equity interest in the Southern Access Extension Project. The remaining balance of $136 million in Property, plant and equipment was reclassified to Long-term investments (Note 11).*

Depreciation expense for the year ended December 31, 2015 was $1,852 million (2014 - $1,461 million).

IMPAIRMENT
The Company recorded impairment charges of $96 million, of which $80 million related to EEP's Berthold rail facility, included within the Liquids Pipelines segment, due to contracts that have not been renewed beyond 2016. The remaining $16 million in impairment charges relate to EEP's non-core Louisiana propylene pipeline asset, included within the Gas Pipelines and Processing segment, following finalization of a contract restructuring with the primary customer.

The impairment charges were based on the amount by which the carrying values of the assets exceeded fair value, determined using expected discounted future cash flows, and were presented within Operating and administrative expense on the Consolidated Statements of Earnings.

DISCONTINUED OPERATIONS
In March 2014, the Company completed the sale of certain of its Offshore assets located within the Stingray corridor to an unrelated third party for cash proceeds of $11 million (US$10 million), subject to working capital adjustments. The gain of $70 million (US$63 million), which resulted from the cash proceeds and the disposition of net liabilities held for sale of $59 million (US$53 million), is presented as Earnings from discontinued operations. The results of operations, including revenues of $4 million and related cash flows, have also been presented as discontinued operations for the year ended December 31, 2014. These Offshore assets were included within the Gas Pipelines and Processing segment.

10. VARIABLE INTEREST ENTITIES

The Company is required to consolidate a VIE in which the Company is the primary beneficiary. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE.

The Company assesses all aspects of its interest in the entity and uses its judgment when determining if the Company is the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. A reassessment of the primary beneficiary conclusion is conducted when there are changes in the facts and circumstances related to a VIE.

MAGICAT HOLDCO LLC
Through its 80% controlling interest in Magicat Holdco LLC acquired on December 31, 2014, the Company is the primary beneficiary of the Magic Valley and Wildcat wind farms *(Note 6)*. These wind farms are partially financed by tax equity investors and are considered VIEs by virtue of the Company's voting rights, its power to direct the activities that most significantly impact the economic performance of the wind farms and the obligation to absorb losses. Magicat Holdco LLC is included within the Green Power and Transmission segment.

As at December 31, 2015, the Company's investment in the Magic Valley and Wildcat wind farms was $394 million (2014 - $394 million).

KEECHI HOLDINGS L.L.C.
The Company initiated construction of the Keechi Wind Project on January 6, 2014. In January 2015, the tax equity investor financed 65% of the project and the wind farm was considered a VIE by virtue of the Company's voting rights, its power to direct the activities that most significantly impact the economic performance of the wind farm and its obligation to absorb losses. Through its position as a managing member and having substantive participation rights in Keechi Wind, LLC the Company is considered the primary beneficiary of the Keechi Wind Project in Texas. Keechi Holdings L.L.C. is included within the Green Power and Transmission segment.

As at December 31, 2015, the Company has contributed $204 million (2014 - $168 million) to Keechi Holdings L.L.C.

At December 31, 2015, the Company's consolidated balance sheet includes total assets of $1,147 million (2014 - $970 million) and total liabilities of $49 million (2014 - $44 million) related to the Magic Valley and Wildcat wind farms and the Keechi Creek Wind Project.

The assets of these VIEs can only be used to settle their obligations. Enbridge does not have an obligation to provide financial support to these VIEs other than an indirect obligation, as prescribed by the terms of certain indemnities and guarantees, to pay the liabilities of the wind farms in the event of a default.

The tax equity investors of these VIEs have priority in the allocation of distributions and tax deductions and credits generated by the project until it achieves a specified return. The Company has an option to purchase the tax equity investors' interest in the project after it has achieved its target return at the greater of fair market value or an amount that would provide the tax equity investors with an internal rate of return specified in the agreements.

ENBRIDGE INCOME FUND

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta and is considered a VIE by virtue of its capital structure. The Company is the primary beneficiary of the Fund through its combined 89.2% (2014 - 66.4%) economic interest held indirectly through a common investment in ENF, a direct common interest in the Fund, a preferred unit investment in ECT, a direct common interest in Enbridge Income Partners GP Inc. and a direct common interest in EIPLP. At December 31, 2015, the Company's direct common interest in the Fund was 49.2% (2014 - 11.9%). As a result of the Canadian Restructuring Plan *(Note 1)*, the Company received ordinary trust units of the Fund and common equity units in EIPLP as part of the consideration, increasing the Company's economic interest in the Fund Group, as well as its direct common unit interest in the Fund. Enbridge also serves in the capacity of Manager of ENF and the Fund Group. The Fund's assets and liabilities and its operating results are included within the Liquids Pipelines, Gas Pipelines and Processing and Green Power and Transmission segments.

As at December 31, 2015, the Company's consolidated balance sheet includes total assets of $113 million (2014 - $4,085 million) and total liabilities of $2,601 million (2014 - $3,213 million) related to the Fund. Certain of the Company's subsidiaries provide unconditional guarantees of the Fund's debt of $2,404 million (2014 - $2,544 million); however, the creditors of the Fund have no recourse to the general credit of the Company.

ENBRIDGE COMMERCIAL TRUST

As a result of the Canadian Restructuring Plan *(Note 1)*, on September 1, 2015, ECT, previously a direct subsidiary of the Fund and consolidated by the Fund, amended its trust indenture to enable Enbridge to appoint the majority of the Trustees to ECT's Board of Trustees resulting in the lack of decision making ability for the holders of the common trust units of ECT. As a result, ECT is considered to be a VIE and although Enbridge does not have a common equity interest in ECT, the Company is considered to be the primary beneficiary of ECT. Enbridge also serves in the capacity of Manager of ECT, as part of the Fund Group.

At December 31, 2015, the Company's consolidated balance sheet did not include any significant assets or liabilities related to ECT.

11. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2015**	2014
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
Seaway Crude Pipeline System	50.0%	**3,251**	2,782
Southern Access Extension Project	65.0%	**713**	263
Enbridge Rail (Philadelphia) L.L.C.	75.0%	**168**	7
Other	30.0% - 43.9%	**69**	58
Gas Distribution			
Noverco Common Shares	38.9%	**-**	-
Gas Pipelines and Processing			
Texas Express Pipeline	35.0%	**515**	442
Alliance Pipeline	50.0%	**427**	374
Aux Sable	42.7% - 50.0%	**344**	311
Vector Pipeline	60.0%	**159**	141
Offshore - various joint ventures	22.0% - 74.3%	**479**	429
Other	33.3% - 70.0%	**12**	10
Green Power and Transmission			
Rampion offshore wind project[1]	24.9%	**201**	-
Other	24.9% - 50.0%	**94**	92
Eliminations and Other			
Other	19.0% - 21.0%	**27**	22
OTHER LONG-TERM INVESTMENTS			
Gas Distribution			
Noverco Preferred Shares		**359**	323
Green Power and Transmission			
Emerging Technologies and Other		**54**	55
Eliminations and Other			
Enbridge Insurance (Barbados Oil) Limited		**35**	23
Enbridge (U.S.) Inc.		**35**	29
Other		**66**	47
		7,008	5,408

1 On November 4, 2015, Enbridge acquired a 24.9% equity interest in Rampion Offshore Wind Limited.

Equity investments include the unamortized excess of the purchase price over the underlying net book value of the investees' assets at the purchase date, which is comprised of $885 million (2014 - $742 million) in Goodwill and $568 million (2014 - $494 million) in amortizable assets.

For the year ended December 31, 2015, dividends received from equity investments was $719 million (2014 - $564 million).

Summarized combined financial information of the Company's interest in unconsolidated equity investments is as follows:

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Revenues	**1,557**	1,790
Commodity costs	**(369)**	(661)
Operating and administrative expense	**(376)**	(444)
Depreciation and amortization	**(274)**	(232)
Other income/(expense)	**4**	(1)
Interest expense	**(67)**	(84)
Earnings before income taxes	**475**	368

December 31,	**2015**	2014
(millions of Canadian dollars)		
Current assets	**389**	472
Property, plant and equipment, net	**6,602**	5,214
Deferred amounts and other assets	**40**	34
Intangible assets, net	**64**	77
Goodwill	**885**	742
Current liabilities	**(500)**	(712)
Long-term debt	**(854)**	(811)
Other long-term liabilities	**(167)**	(85)
Net assets	**6,459**	4,931

Alliance Pipeline
Certain assets of the Alliance Pipeline are pledged as collateral to Alliance Pipeline lenders.

Southern Access Extension Project
On July 1, 2014, under an agreement with an unrelated third party, the Company sold a 35% equity interest in the Southern Access Extension Project (the Project). Prior to this sale, the subsidiary executing the Project was wholly-owned and consolidated within the Liquids Pipelines segment. The Company concluded that under the agreement, the purchaser of the 35% equity interest is entitled to substantive participating rights; however, the Company continues to exercise significant influence. As a result, effective July 1, 2014, the Company discontinued consolidation of the Project and recognized its remaining 65% equity interest as a long-term equity investment within the Liquids Pipelines segment.

Noverco
As at December 31, 2015, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2014 - 38.9%) of its common shares and an investment in preferred shares. The preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in 10 years plus a range of 4.3% to 4.4%.

As at December 31, 2015, Noverco owned an approximate 3.6% (2014 - 3.6%) reciprocal shareholding in common shares of Enbridge. Through secondary offerings, Noverco sold 1.3 million common shares in 2014. The transaction was recognized as an issuance of treasury stock on the Consolidated Statements of Changes in Equity.

As a result of Noverco's reciprocal shareholding in Enbridge common shares, the Company has an indirect pro-rata interest of 1.4% (2014 - 1.4%) in its own shares. Both the equity investment in Noverco and shareholders' equity have been reduced by the reciprocal shareholding of $83 million at December 31, 2015 (2014 - $83 million). Noverco records dividends paid by the Company as dividend income and the Company eliminates these dividends from its equity earnings of Noverco. The Company records its pro-rata share of dividends paid by the Company to Noverco as a reduction of dividends paid and an increase in the Company's investment in Noverco.

Rampion Offshore Wind Project
In November 2015, Enbridge announced the acquisition of a 24.9% interest in the 400 MW Rampion Offshore Wind Project (the Rampion project) in the United Kingdom (UK), located 13 kilometres (8 miles) off the UK Sussex coast at its nearest point. The Company's total investment in the project through construction is expected to be approximately $750 million (£370 million). The Rampion project was developed and is being constructed by E.ON Climate & Renewables UK Limited, a subsidiary of E.ON SE (E.ON). Construction of the wind farm began in September 2015 and it is expected to be fully operational in 2018. The Rampion project is backed by revenues from the UK's fixed price Renewable Obligation certificates program and a 15-year power purchase agreement. Under the terms of the purchase agreement, Enbridge became one of the three shareholders in Rampion Offshore Wind Limited which owns the Rampion project with the UK Green Investment Bank plc holding a 25% interest and E.ON retaining the balance of 50.1% interest. Enbridge's portion of the costs incurred to date is approximately $201 million (£96.9 million) presented in Long-term investments.

12. RESTRICTED LONG-TERM INVESTMENTS

Effective January 1, 2015, the Company began collecting and setting aside funds to cover future pipeline abandonment costs for all NEB regulated pipelines as a result of the NEB's regulatory requirements under LMCI. The funds collected are held in trusts in accordance with the NEB decision. The funds collected from shippers are reported within Transportation and other services revenues on the Consolidated Statements of Earnings and Restricted long-term investments on the Consolidated Statements of Financial Position. Concurrently, the Company reflects the future abandonment cost as an increase to Operating and administrative expense on the Consolidated Statements of Earnings and Other long-term liabilities on the Consolidated Statements of Financial Position.

As at December 31, 2015, the Company had restricted long-term investments held in trust, invested in Canadian Treasury bonds, and are classified as held for sale and carried at fair value of $49 million (2014 - nil). As at December 31, 2015, the Company had estimated future abandonment costs of $48 million (2014 - nil) and restricted cash of nil (2014 - nil) related to LMCI.

13. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory assets *(Note 5)*	**1,661**	1,751
Long-term portion of derivative assets *(Note 24)*	**373**	199
Affiliate long-term notes receivable *(Note 30)*	**152**	183
Contractual receivables	**432**	382
Deferred financing costs	**52**	51
Other	**490**	526
	3,160	3,092

As at December 31, 2015, deferred amounts of $406 million (2014 - $366 million) were subject to amortization and are presented net of accumulated amortization of $193 million (2014 - $189 million). Amortization expense for the year ended December 31, 2015 was $55 million (2014 - $38 million).

14. INTANGIBLE ASSETS

December 31, 2015	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	11.6%	**1,295**	**516**	**779**
Natural gas supply opportunities	4.0%	**484**	**122**	**362**
Power purchase agreements	3.8%	**94**	**11**	**83**
Land leases, permits and other	4.2%	**163**	**39**	**124**
		2,036	**688**	**1,348**

December 31, 2014	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	12.9%	1,049	337	712
Natural gas supply opportunities	3.7%	340	83	257
Power purchase agreements	3.4%	113	11	102
Land leases, permits and other	4.0%	124	29	95
		1,626	460	1,166

Total amortization expense for intangible assets was $158 million (2014 - $106 million) for the year ended December 31, 2015. The Company expects amortization expense for intangible assets for the years ending December 31, 2016 through 2020 of $180 million, $160 million, $144 million, $130 million and $117 million, respectively.

15. GOODWILL

	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Balance at January 1, 2014	52	-	393	-	-	-	445
Foreign exchange and other	3	-	35	-	-	-	38
Balance at December 31, 2014	**55**	**-**	**428**	**-**	**-**	**-**	**483**
Foreign exchange and other	**5**	**-**	**30**	**-**	**2**	**-**	**37**
Impairment	**-**	**-**	**(440)**	**-**	**-**	**-**	**(440)**
Balance at December 31, 2015	**60**	**-**	**18**	**-**	**2**	**-**	**80**

GAS PIPELINES AND PROCESSING

Impairment

During the year ended December 31, 2015, the Company recorded an impairment charge of $440 million ($167 million after-tax attributable to Enbridge) related to EEP's natural gas and NGL businesses, which EEP holds directly and indirectly through its partially-owned subsidiary, MEP. Due to a prolonged decline in commodity prices, reduction in producers' expected drilling programs negatively impacted forecasted cash flows from EEP's natural gas and NGL systems. This change in circumstance led to the completion of an impairment test, resulting in a full impairment of goodwill on EEP's natural gas and NGL businesses.

In performing the impairment assessment, EEP measured the fair value of its reporting units primarily by using a discounted cash flow analysis and it also considered overall market capitalization of its business, cash flow measurement data and other factors. EEP's estimate of fair value required it to use significant unobservable inputs representative of a Level 3 fair value measurement, including assumptions related to the future performance of its reporting units.

The Company did not recognize any goodwill impairment for the year ended December 31, 2014.

16. ACCOUNTS PAYABLE AND OTHER

December 31,	**2015**	2014
(millions of Canadian dollars)		
Operating accrued liabilities	**3,028**	2,939
Trade payables	**561**	414
Construction payables	**750**	746
Current derivative liabilities *(Note 24)*	**1,945**	1,020
Contractor holdbacks	**299**	368
Taxes payable	**376**	555
Security deposits	**62**	63
Asset retirement obligations *(Note 19)*	**9**	53
Other	**321**	286
	7,351	6,444

17. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2015**	2014
(millions of Canadian dollars)				
Enbridge Inc.				
United States dollar term notes[1]	3.3%	2016-2044	**4,221**	3,886
Medium-term notes	4.3%	2016-2064	**5,698**	6,048
Commercial paper and credit facility draws[2]			**5,667**	4,525
Other[3]			**7**	-
Enbridge (U.S.) Inc.				
Commercial paper and credit facility draws[4]			**1,665**	1,657
Medium-term notes[5]	5.1%	2020	**14**	12
Enbridge Energy Partners, L.P.				
Senior notes[6]	6.2%	2016-2045	**7,404**	4,350
Commercial paper and credit facility draws[7]			**1,988**	2,056
Junior subordinated notes[8]	8.1%	2067	**554**	464
Enbridge Gas Distribution Inc.				
Medium-term notes	4.6%	2016-2050	**3,603**	3,033
Debentures	9.9%	2024	**85**	85
Commercial paper and credit facility draws			**599**	939
Enbridge Income Fund				
Medium-term notes	3.8%	2016-2044	**2,405**	2,405
Commercial paper and credit facility draws			**-**	140
Enbridge Pipelines (Southern Lights) L.L.C.				
Medium-term notes[9,10]	4.0%	2016-2040	**1,425**	1,223
Enbridge Pipelines Inc.				
Medium-term notes[11]	4.7%	2018-2045	**3,725**	2,974
Commercial paper and credit facility draws			**1,346**	163
Debentures	8.2%	2024	**200**	200
Promissory note[12]			**-**	103
Other[3]			**4**	9
Enbridge Southern Lights LP				
Medium-term notes[10]	4.0%	2040	**336**	348
Midcoast Energy Partners, L.P.				
Senior notes[13]	4.1%	2019-2024	**554**	465
Commercial paper and credit facility draws[14]			**678**	418
Other[15]			**(198)**	(151)
Total debt			**41,980**	35,352
Current maturities			**(1,990)**	(1,004)
Short-term borrowings[16]			**(599)**	(1,041)
Long-term debt			**39,391**	33,307

1 *2015 - US$3,050 million (2014 - US$3,350 million).*
2 *2015 - $4,168 million and US$1,084 million (2014 - $3,217 million and US$1,127 million)*
3 *Primarily capital lease obligations.*
4 *2015 - US$1,203 million (2014 - US$1,428 million).*
5 *2015 - US$10 million (2014 - US$10 million).*
6 *2015 - US$5,350 million (2014 - US$3,750 million).*
7 *2015 - US$1,436 million (2014 - US$1,772 million).*
8 *2015 - US$400 million (2014 - US$400 million).*
9 *2015 - US$1,030 million (2014 - US$1,054 million).*
10 *On August 18, 2014, long-term private debt was issued for $352 million and US$1,601 million related to Southern Lights project financing. The proceeds were utilized to repay the construction credit facilities on a dollar-for-dollar basis.*
11 *Included in medium-term notes is $100 million with a maturity date of 2112.*
12 *A non-interest bearing demand promissory note that was paid on January 9, 2015.*
13 *2015 - US$400 million (2014 - US$400 million).*
14 *2015 - US$490 million (2014 - US$360 million).*
15 *Primarily debt discount and debt issue costs.*
16 *Weighted average interest rate - 0.8% (2014 - 1.4%).*

For the years ending December 31, 2016 through 2020 debenture and term note maturities are $1,987 million, $2,639 million, $1,197 million, $1,883 million, $2,841 million, respectively, and $19,677 million thereafter. The Company's debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2016 through 2020 are $1,704 million, $1,599 million, $1,439 million, $1,246 million and $1,048 million, respectively. At December 31, 2015 and 2014, all debt was unsecured.

INTEREST EXPENSE

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Debentures and term notes	**1,805**	1,425
Commercial paper and credit facility draws	**172**	71
Southern Lights project financing	**-**	49
Capitalized	**(353)**	(416)
	1,624	1,129

INTEREST EXPENSE

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Enbridge Inc.	**970**	598
Enbridge (U.S.) Inc.	**54**	19
Enbridge Energy Partners, L.P.	**369**	458
Enbridge Gas Distribution Inc.	**175**	154
Enbridge Income Fund	**106**	76
Enbridge Pipelines (Southern Lights) L.L.C.	**45**	36
Enbridge Pipelines Inc.	**210**	171
Enbridge Southern Lights LP	**14**	14
Midcoast Energy Partners, L.P.	**34**	19
Capitalized	**(353)**	(416)
	1,624	1,129

CREDIT FACILITIES

The following table provides details of the Company’s committed credit facilities at December 31, 2015 and December 31, 2014.

		2015			2014
December 31,	Maturity	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Inc.	2017-2020	**6,988**	**5,692**	**1,296**	9,025
Enbridge (U.S.) Inc.	2017	**4,470**	**1,665**	**2,805**	3,747
Enbridge Energy Partners, L.P.	2017-2020	**3,598**	**2,054**	**1,544**	3,045
Enbridge Gas Distribution Inc.	2017-2019	**1,010**	**603**	**407**	1,008
Enbridge Income Fund	2018	**1,500**	**11**	**1,489**	500
Enbridge Pipelines (Southern Lights) L.L.C.	2017	**28**	**-**	**28**	23
Enbridge Pipelines Inc.	2017	**3,000**	**1,346**	**1,654**	300
Enbridge Southern Lights LP	2017	**5**	**-**	**5**	5
Midcoast Energy Partners, L.P.	2018	**1,121**	**678**	**443**	986
Total committed credit facilities[2]		**21,720**	**12,049**	**9,671**	18,639

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

2 *On August 18, 2014, long-term private debt was issued for $352 million and US$1,061 million related to Southern Lights project financing. The proceeds were utilized to repay the construction credit facilities on a dollar-for-dollar basis.*

In addition to the committed credit facilities noted above, the Company also has $349 million (2014 - $361 million) of uncommitted demand credit facilities, of which $185 million (2014 - $80 million) was unutilized as at December 31, 2015.

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2017 to 2020.

Commercial paper and credit facility draws, net of short-term borrowings, of $11,344 million (2014 - $8,960 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

The Company's credit facility agreements include standard events of default and covenant provisions whereby accelerated repayment may be required if the Company were to default on payment or violate certain covenants. As at December 31, 2015, the Company was in compliance with all debt covenants.

18. OTHER LONG-TERM LIABILITIES

December 31,	**2015**	2014
(millions of Canadian dollars)		
Regulatory liabilities *(Note 5)*	**787**	802
Derivative liabilities *(Note 24)*	**3,950**	2,078
Pension and OPEB liabilities *(Note 26)*	**517**	584
Asset retirement obligations *(Note 19)*	**189**	132
Environmental liabilities	**89**	70
Other	**524**	375
	6,056	4,041

19. ASSET RETIREMENT OBLIGATIONS

The liability for the expected cash flows as recognized in the financial statements reflected discount rates ranging from 1.7% to 9.4% (2014 - 4.6% to 8.1%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Obligations at beginning of year	**185**	24
Liabilities incurred	**2**	177
Liabilities settled	**(45)**	(24)
Change in estimate	**30**	-
Foreign currency translation adjustment	**21**	5
Accretion expense	**5**	3
Obligations at end of year	**198**	185
Presented as follows:		
Accounts payable and other *(Note 16)*	**9**	53
Other long-term liabilities *(Note 18)*	**189**	132
	198	185

In 2014, the Company recognized ARO in the amount of $177 million. Of this amount, $74 million related to the decommissioning of certain portions of Line 6B of EEP's Lakehead System and $103 million related to the Canadian and United States portions of the Line 3 Replacement Program, which is targeted to be completed in 2019, whereby the Company will replace the existing Line 3 pipeline in Canada and the United States.

20. NONCONTROLLING INTERESTS

December 31,	**2015**	2014
(millions of Canadian dollars)		
Enbridge Energy Partners, L.P.	**412**	748
Enbridge Energy Management, L.L.C. (EEM)	**203**	790
Enbridge Gas Distribution Inc. preferred shares	**100**	100
Renewable energy assets	**561**	351
Other	**24**	26
	1,300	2,015

ENBRIDGE ENERGY PARTNERS, L.P.

Noncontrolling interests in EEP represented the 80.0% (2014 - 79.5%) interest in EEP held by public unitholders, as well as interests of third parties in subsidiaries of EEP, including MEP. The net decrease in the carrying value of Noncontrolling interests in EEP was due to the transactions described below, which were partially offset by comprehensive income attributable to noncontrolling interests in EEP during the year ended December 31, 2015.

On January 2, 2015, Enbridge transferred its 66.7% interest in the United States segment of the Alberta Clipper pipeline, held through a wholly-owned Enbridge subsidiary in the United States, to EEP for aggregate consideration of $1.1 billion (US$1 billion), consisting of approximately $814 million (US$694 million) of Class E equity units issued to Enbridge by EEP and the repayment of approximately $359 million (US$306 million) of indebtedness owed to Enbridge. Prior to the transfer, EEP owned the remaining 33.3% interest in the United States segment of the Alberta Clipper pipeline.

The Class E units issued to Enbridge are entitled to the same distributions as the Class A units held by the public and are convertible into Class A units on a one-for-one basis at Enbridge's option. The transaction applies to all distributions declared subsequent to the transfer. The Class E units are redeemable at EEP's option after 30 years, if not converted by Enbridge prior to that time. The units have a liquidation preference equal to their notional value at December 23, 2014 of US$38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of EEP's Class A common units. EEP recorded the Class E units at fair value. As a result, the Company recorded a decrease in Noncontrolling interests of $304 million and increases in Additional paid-in capital and Deferred income tax liabilities of $218 million and $86 million, respectively.

On March 13, 2015, EEP completed a listed share issuance. The Company participated only to the extent to maintain its 2% General Partner (GP) interest. The listed share issuance resulted in contributions of $366 million (US$289 million) from noncontrolling interest holders. Enbridge's noncontrolling interests in EEP increased from 79.5% to 80.0% as a result of the listed share issuance.

During the year ended December 31, 2015, EEP distributed $630 million (2014 - $504 million) to its noncontrolling interest holders in line with EEP's objective to make quarterly distributions in an amount equal to its available cash, as defined in its partnership agreement and as approved by EEP's Board of Directors.

Effective July 1, 2014, Enbridge Energy Company, Inc., a wholly-owned subsidiary of Enbridge and the GP of EEP, entered into an equity restructuring transaction in which the Company irrevocably waived its right to receive cash distributions and allocations in excess of 2% in respect of its GP interest in the existing incentive distribution rights (IDR) in exchange for the issuance of (i) 66.1 million units of a new class of EEP units designated as Class D Units, and (ii) 1,000 units of a new class of EEP units designated as Incentive Distribution Units (IDU). The Class D Units entitle the Company to receive quarterly distributions equal to the distribution paid on EEP's common units. This restructuring decreases the Company's share of incremental cash distributions from 48% of all distributions in excess of US$0.4950 per unit per quarter down to 23% of all distributions in excess of EEP's current quarterly distribution of US$0.5435 per unit per quarter. The transaction applies to all distributions declared subsequent to the effective date. EEP recorded the Class D Units and IDU at fair value, which resulted in a reduction to the carrying amounts of the GP and limited partner capital accounts on a pro-rata basis. As a result, the Company recorded a decrease in Noncontrolling interests of $2,363 million inclusive of CTA and increases in Additional paid-in capital and Deferred income tax liabilities of $1,601 million and $762 million, respectively.

On July 1, 2014, EEP completed the sale of 12.6% limited partnership interest in its natural gas and NGL midstream business to its subsidiary, MEP, for cash proceeds of $376 million (US$350 million). Upon finalization of this transaction, EEP continued to retain a 2% GP interest, an approximate 52% limited partner interest and all IDR in MEP. However, EEP's direct interest in entities or partnerships holding the natural gas and NGL midstream operations reduced from 61% to 48%, with the remaining ownership held by MEP.

ENBRIDGE ENERGY MANAGEMENT, L.L.C.
Noncontrolling interests in EEM represented the 88.3% (2014 - 88.3%) of the listed shares of EEM not held by the Company. During the year ended December 31, 2015, the decrease in the carrying value of Noncontrolling interests in EEM is primarily due to comprehensive loss attributable to noncontrolling interests in EEM, along with the fair value allocation attributable to EEM as a result of the Class E equity units issued to Enbridge by EEP as discussed above.

During the year ended December 31, 2014, the decrease in the carrying value of Noncontrolling interests in EEM is due to the fair value allocation attributable to EEM as a result of the EEP equity restructuring as discussed above.

ENBRIDGE GAS DISTRIBUTION INC.
The Company owns 100% of the outstanding common shares of EGD; however, the four million Cumulative Redeemable EGD Preferred Shares held by third parties are entitled to a claim on the assets of EGD prior to the common shareholder. The preferred shares have no fixed maturity date and have floating adjustable cash dividends that are payable at 80% of the prime rate. EGD may, at its option, redeem all or a portion of the outstanding shares for $25 per share plus all accrued and unpaid dividends to the redemption date. As at December 31, 2015, no preferred shares have been redeemed.

RENEWABLE ENERGY ASSETS
Renewable energy assets include Magic Valley and Wildcat wind farms acquired on December 31, 2014 *(Note 6)* and Keechi Wind Project, a VIE *(Note 10)*. During the year ended December 31, 2015, the net increase in the carrying value of Noncontrolling interests in Renewable energy assets is primarily due to contributions, net of distributions, received from noncontrolling interests, along with comprehensive income attributable to noncontrolling interests during the year ended December 31, 2015.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Balance at beginning of year	**2,249**	1,053
Loss	**(3)**	(11)
Other comprehensive income/(loss), net of tax		
Change in unrealized gains/(loss) on cash flow hedges	**(7)**	(15)
Other comprehensive loss from equity investees	**(12)**	-
Reclassification to earnings of realized cash flow hedges	**2**	-
Reclassification to earnings of unrealized cash flow hedges	**2**	-
Change in foreign currency translation adjustment	**18**	5
Other comprehensive income/(loss)	**3**	(10)
Distributions to unitholders	**(114)**	(79)
Contributions from unitholders	**670**	323
Reversal of cumulative redemption value adjustment attributable to ECT preferred units	**(541)**	-
Dilution loss on Enbridge Income Fund issuance of trust units	**(355)**	-
Dilution loss on Enbridge Income Fund equity investment	**(132)**	-
Dilution gain on Enbridge Income Fund indirect equity investment	**5**	-
Redemption value adjustment	**359**	973
Balance at end of year	**2,141**	2,249

Redeemable noncontrolling interests in the Fund at December 31, 2015 represented 40.7% (2014 - 70.6%) of interests in the Fund's trust units that are held by third parties.

In September 2015, Enbridge's unitholdings in the Fund increased upon closing of the Canadian Restructuring Plan *(Note 1)*, resulting in a decrease in redeemable noncontrolling interests from 70.6% to 34.3%.

Upon closing of the Canadian Restructuring Plan, ECT, an equity investment of the Fund, reclassified its Preferred Units from mezzanine equity to liabilities. Accordingly, ECT reduced the recorded redemption value of its Preferred Units to their aggregate par value, resulting in an increase to the Fund's equity investment in ECT. This resulted in an adjustment to redeemable noncontrolling interests of approximately $541 million.

Upon closing of the Canadian Restructuring Plan, EIPLP, an indirect equity investment of the Fund, issues Temporary Performance Distribution Rights (TPDR) to Enbridge each month in the form of Class D units of EIPLP. The Class D unitholders receive a distribution each month equal to the per unit amount paid on Class C units of EIPLP, but to be paid in kind in additional Class D units. The issuances of TPDR and additional Class D units result in a dilution gain for the Fund's indirect equity investment in EIPLP. A dilution gain for redeemable noncontrolling interests of $5 million was recorded for the year ended December 31, 2015.

In November 2015, ENF completed a bought deal public offering of common shares for approximately $700 million and issued additional common shares to Enbridge for approximately $174 million in order for Enbridge to maintain its 19.9% in ENF. ENF used the aggregate proceeds of $874 million to subscribe for additional trust units of the Fund. Enbridge did not participate in this offering, resulting in an increase in redeemable noncontrolling interests from 34.3% to 40.7%. This resulted in contributions of $670 million, net of share issue costs, from redeemable noncontrolling interest holders and a dilution loss for redeemable noncontrolling interests of $355 million for the year ended December 31, 2015.

In November 2015, the Fund used the aggregate proceeds of $874 million from the issuance of trust units to ENF to purchase additional common units of ECT, and ECT used the aggregate proceeds of $874 million to purchase additional Class A units of EIPLP, resulting in a dilution loss for ECT. This dilution loss resulted in a dilution loss for Fund's equity investment in ECT and a dilution loss for redeemable noncontrolling interests of $132 million for the year ended December 31, 2015.

In November 2014, the Fund Group acquired Enbridge's 50% interest in the United States portion of Alliance Pipeline and subscribed for and purchased Class A units of Enbridge's subsidiaries that indirectly own the Canadian and United States segments of the Southern Lights Pipeline for a total consideration of approximately $1.8 billion, including $421 million in cash, $878 million in the form of a long-term note payable by the Fund, bearing interest of 5.5% per annum and was fully repaid at December 31, 2015, and $461 million in the form of preferred units of ECT, which at the time of the transfer was a subsidiary of the Fund. To fund the cash component of the consideration, the Fund issued approximately $421 million of trust units to ENF. To purchase the trust units from the Fund, ENF completed a bought deal public offering of common shares for approximately $337 million and issued additional common shares to Enbridge for approximately $84 million in order for Enbridge to maintain its 19.9% interest in ENF. As a result of the transfer, redeemable noncontrolling interests in the Fund increased from 68.6% to 70.6% and contributions of $323 million, net of share issue costs, were received from redeemable noncontrolling interest holders.

Distributions to noncontrolling unitholders were made on a monthly basis for the years ended December 31, 2015 and 2014 in line with the Fund's objective of distributing a high proportion of its cash available for distribution, as approved by its Board of Trustees.

21. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and an unlimited number of preference shares.

COMMON SHARES

	2015		2014	
December 31,	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Balance at beginning of year	**852**	**6,669**	831	5,744
Common shares issued[1]	**-**	**-**	9	446
Dividend Reinvestment and Share Purchase Plan (DRIP)	**12**	**646**	9	428
Shares issued on exercise of stock options	**4**	**76**	3	51
Balance at end of year	**868**	**7,391**	852	6,669

1 Gross proceeds - nil (2014 - $460 million); net issuance costs - nil (2014 - $14 million).

PREFERENCE SHARES

December 31,	2015 Number of Shares	2015 Amount	2014 Number of Shares	2014 Amount
(millions of Canadian dollars; number of preference shares in millions)				
Preference Shares, Series A	**5**	**125**	5	125
Preference Shares, Series B	**20**	**500**	20	500
Preference Shares, Series D	**18**	**450**	18	450
Preference Shares, Series F	**20**	**500**	20	500
Preference Shares, Series H	**14**	**350**	14	350
Preference Shares, Series J	**8**	**199**	8	199
Preference Shares, Series L	**16**	**411**	16	411
Preference Shares, Series N	**18**	**450**	18	450
Preference Shares, Series P	**16**	**400**	16	400
Preference Shares, Series R	**16**	**400**	16	400
Preference Shares, Series 1	**16**	**411**	16	411
Preference Shares, Series 3	**24**	**600**	24	600
Preference Shares, Series 5	**8**	**206**	8	206
Preference Shares, Series 7	**10**	**250**	10	250
Preference Shares, Series 9	**11**	**275**	11	275
Preference Shares, Series 11	**20**	**500**	20	500
Preference Shares, Series 13	**14**	**350**	14	350
Preference Shares, Series 15	**11**	**275**	11	275
Issuance costs		**(137)**		(137)
Balance at end of period		**6,515**		6,515

Characteristics of the preference shares are as follows:

	Initial Yield	Dividend[1]	Per Share Base Redemption Value[2]	Redemption and Conversion Option Date[2,3]	Right to Convert Into[3,4]
(Canadian dollars unless otherwise stated)					
Preference Shares, Series A	5.5%	$1.375	$25	-	-
Preference Shares, Series B	4.0%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.0%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.0%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.0%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.0%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.0%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.0%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.0%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R	4.0%	$1.000	$25	June 1, 2019	Series S
Preference Shares, Series 1	4.0%	US$1.000	US$25	June 1, 2018	Series 2
Preference Shares, Series 3	4.0%	$1.000	$25	September 1, 2019	Series 4
Preference Shares, Series 5	4.4%	US$1.100	US$25	March 1, 2019	Series 6
Preference Shares, Series 7	4.4%	$1.100	$25	March 1, 2019	Series 8
Preference Shares, Series 9	4.4%	$1.100	$25	December 1, 2019	Series 10
Preference Shares, Series 11	4.4%	$1.100	$25	March 1, 2020	Series 12
Preference Shares, Series 13	4.4%	$1.100	$25	June 1, 2020	Series 14
Preference Shares, Series 15	4.4%	$1.100	$25	September 1, 2020	Series 16

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

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

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.

4 Holders will be entitled to receive quarterly floating rate cumulative dividends per share at a rate equal to: $25 x (number of days in quarter/365) x (90-day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14) or 2.7% (Series 16); or US$25 x (number of days in quarter/365) x (three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6)).

EARNINGS PER COMMON SHARE
Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 12 million (2014 - 12 million) resulting from the Company's reciprocal investment in Noverco.

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

December 31,	**2015**	2014
(number of common shares in millions)		
Weighted average shares outstanding	**847**	829
Effect of dilutive options	**11**	11
Diluted weighted average shares outstanding	**858**	840

For the year ended December 31, 2015, 7,960,028 anti-dilutive stock options (2014 - 6,058,580) with a weighted average exercise price of $55.81 (2014 - $48.78) were excluded from the diluted earnings per common share calculation.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN
Under the DRIP, registered shareholders may reinvest dividends in common shares of the Company and make additional optional cash payments to purchase common shares, free of brokerage or other charges. Participants in the Company's DRIP receive a 2% discount on the purchase of common shares with reinvested dividends.

SHAREHOLDER RIGHTS PLAN
The Shareholder Rights Plan is designed to encourage the fair treatment of shareholders in connection with any takeover offer for the Company. Rights issued under the plan become exercisable when a person and any related parties acquires or announces its intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Company's Board of Directors. Should such an acquisition occur, each rights holder, other than the acquiring person and related parties, will have the right to purchase common shares of the Company at a 50% discount to the market price at that time.

22. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains four long-term incentive compensation plans: the ISO Plan, the PSO Plan, the PSU Plan and the RSU Plan. A maximum of 60 million common shares were reserved for issuance under the 2002 ISO plan, of which 50 million have been issued to date. A further 71 million common shares have been reserved for issuance for the 2007 ISO and PSO plans, of which 11 million have been exercised and issued from treasury to date. The PSU and RSU plans grant notional units as if a unit was one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS

Key employees are granted ISO to purchase common shares at the market price on the grant date. ISO vest in equal annual instalments over a four-year period and expire 10 years after the issue date.

December 31, 2015	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**31,330**	**34.97**		
Options granted	**5,852**	**59.14**		
Options exercised[1]	**(4,224)**	**26.61**		
Options cancelled or expired	**(170)**	**44.87**		
Options outstanding at end of year	**32,788**	**40.31**	**6.3**	**525**
Options vested at end of year[2]	**18,297**	**31.66**	**4.8**	**451**

1 The total intrinsic value of ISO exercised during the year ended December 31, 2015 was $126 million (2014 - $117 million) and cash received on exercise was $43 million (2014 - $37 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2015 was $34 million (2014 - $26 million).

Weighted average assumptions used to determine the fair value of ISO granted using the Black-Scholes-Merton option pricing model are as follows:

Year ended December 31,	**2015**	2014
Fair value per option *(Canadian dollars)*[1]	**6.48**	5.53
Valuation assumptions		
Expected option term *(years)*[2]	**5**	5
Expected volatility[3]	**19.9%**	16.9%
Expected dividend yield[4]	**3.2%**	2.9%
Risk-free interest rate[5]	**0.9%**	1.6%

1 Options granted to United States employees are based on New York Stock Exchange prices. The option value and assumptions shown are based on a weighted average of the United States and the Canadian options. The fair values per option were $6.22 (2014 - $5.45) for Canadian employees and US$6.16 (2014 - US$5.35) for United States employees.

2 The expected option term is six years based on historical exercise practice and three years for retirement eligible employees.

3 Expected volatility is determined with reference to historic daily share price volatility and consideration of the implied volatility observable in call option values near the grant date.

4 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.

5 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields and the United States Treasury Bond Yields.

Compensation expense recorded for the year ended December 31, 2015 for ISO was $35 million (2014 - $29 million). At December 31, 2015, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the ISO Plan was $47 million. The cost is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK OPTIONS

PSO are granted to executive officers and become exercisable when both performance targets and time vesting requirements have been met. PSO were granted on August 15, 2007, February 19, 2008, August 15, 2012 and March 13, 2014 under the 2007 plan. All performance targets for the 2007 and 2008 grants have been met. The time vesting requirements were fulfilled evenly over a five-year period ending on August 15, 2012 with the options being exercisable until August 15, 2015. Time vesting requirements for the 2012 grant will be fulfilled evenly over a five-year term, ending August 15, 2017. The 2012 grant's performance targets are based on the Company's share price and must be met by February 15, 2019 or the options expire. As at December 31, 2015, all performance targets have been met and the options are exercisable until August 15, 2020. Time vesting requirements for the 2014 grant will be fulfilled evenly over a four-year term, ending March 13, 2018. The 2014 grant's performance targets are based on the

Company's share price and must be met by February 15, 2019 or the options expire. As at December 31, 2015, all performance targets have been met and the options are exercisable until August 15, 2020.

December 31, 2015	Number	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(options in thousands; intrinsic value in millions of Canadian dollars)				
Options outstanding at beginning of year	**4,511**	**35.97**		
Options granted	**-**	**-**		
Options exercised[1]	**(830)**	**19.44**		
Options cancelled or expired	**(464)**	**39.34**		
Options outstanding at end of year	**3,217**	**39.75**	**3.9**	**53**
Options vested at end of year[2]	**2,307**	**39.48**	**3.7**	**39**

1 The total intrinsic value of PSO exercised during the year ended December 31, 2015 was $43 million (2014 - nil) and cash received on exercise was $13 million (2014 - nil).
2 The total fair value of options vested under the PSO Plan during the year ended December 31, 2015 was $6 million (2014 - $5 million).

Assumptions used to determine the fair value of PSO granted using the Bloomberg barrier option valuation model are as follows:

Year ended December 31,	2014
Fair value per option *(Canadian dollars)*	5.77
Valuation assumptions	
Expected option term *(years)*[1]	6.5
Expected volatility[2]	15.0%
Expected dividend yield[3]	2.8%
Risk-free interest rate[4]	1.7%

1 The expected option term is based on historical exercise practice.
2 Expected volatility is determined with reference to historic daily share price volatility.
3 The expected dividend yield is the current annual dividend at the grant date divided by the current stock price.
4 The risk-free interest rate is based on the Government of Canada's Canadian Bond Yields.

Compensation expense recorded for the year ended December 31, 2015 for PSO was $3 million (2014 - $3 million). At December 31, 2015, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PSO Plan was $5 million. The cost is expected to be fully recognized over a weighted average period of approximately two years.

PERFORMANCE STOCK UNITS

The Company has a PSU Plan for executives where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's weighted average share price for 20 days prior to the maturity of the grant and by a performance multiplier. The performance multiplier ranges from zero, if the Company's performance fails to meet threshold performance levels, to a maximum of two if the Company performs within the highest range of its performance targets. The performance multiplier is derived through a calculation of the Company's price/earnings ratio relative to a specified peer group of companies and the Company's earnings per share, adjusted for unusual, non-operating or non-recurring items, relative to targets established at the time of grant. To calculate the 2015 expense, multipliers of two, were used for each of the 2013, 2014 and 2015 PSU grants.

December 31, 2015	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**555**		
Units granted	**244**		
Units cancelled	**(9)**		
Units matured[1]	**(282)**		
Dividend reinvestment	**28**		
Units outstanding at end of year	**536**	**1.5**	**47**

1 The total amount paid during the year ended December 31, 2015 for PSU was $35 million (2014 - $36 million).

Compensation expense recorded for the year ended December 31, 2015 for PSU was $12 million (2014 - $40 million). As at December 31, 2015, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $28 million and is expected to be fully recognized over a weighted average period of approximately two years.

RESTRICTED STOCK UNITS

Enbridge has a RSU Plan where cash awards are paid to certain non-executive employees of the Company following a 35-month maturity period. RSU holders receive cash equal to the Company's weighted average share price for 20 days prior to the maturity of the grant multiplied by the units outstanding on the maturity date.

December 31, 2015	Number	Weighted Average Remaining Contractual Life *(years)*	Aggregate Intrinsic Value
(units in thousands; intrinsic value in millions of Canadian dollars)			
Units outstanding at beginning of year	**1,959**		
Units granted	**854**		
Units cancelled	**(101)**		
Units matured[1]	**(904)**		
Dividend reinvestment	**98**		
Units outstanding at end of year	**1,906**	**1.4**	**88**

1 The total amount paid during the year ended December 31, 2015 for RSU was $45 million (2014 - $45 million).

Compensation expense recorded for the year ended December 31, 2015 for RSU was $47 million (2014 - $44 million). As at December 31, 2015, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $64 million and is expected to be fully recognized over a weighted average period of approximately one year.

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

Changes in AOCI attributable to Enbridge common shareholders for the years ended December 31, 2015 and 2014 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2015	**(488)**	**108**	**309**	**(5)**	**(359)**	**(435)**
Other comprehensive income/(loss) retained in AOCI	**73**	**(952)**	**3,056**	**47**	**65**	**2,289**
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	**(34)**	**-**	**-**	**-**	**-**	**(34)**
Commodity contracts[2]	**(11)**	**-**	**-**	**-**	**-**	**(11)**
Foreign exchange contracts[3]	**7**	**-**	**-**	**-**	**-**	**7**
Other contracts[4]	**26**	**-**	**-**	**-**	**-**	**26**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**-**	**-**	**-**	**-**	**32**	**32**
Other comprehensive loss reclassified to earnings of derecognized cash flow hedges *(Note 24)*	**(338)**	**-**	**-**	**-**	**-**	**(338)**
	(277)	**(952)**	**3,056**	**47**	**97**	**1,971**
Tax impact						
Income tax on amounts retained in AOCI	**(29)**	**49**	**-**	**(5)**	**(14)**	**1**
Income tax on amounts reclassified to earnings	**15**	**-**	**-**	**-**	**(11)**	**4**
Income tax on amounts reclassified to earnings of derecognized cash flow hedges *(Note 24)*	**91**	**-**	**-**	**-**	**-**	**91**
	77	**49**	**-**	**(5)**	**(25)**	**96**
Balance at December 31, 2015	**(688)**	**(795)**	**3,365**	**37**	**(287)**	**1,632**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2014	(1)	378	(778)	(15)	(183)	(599)
Other comprehensive income/(loss) retained in AOCI	(857)	(301)	1,087	10	(265)	(326)
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	201	-	-	-	-	201
Commodity contracts[2]	(2)	-	-	-	-	(2)
Foreign exchange contracts[3]	8	-	-	-	-	8
Other contracts[4]	(23)	-	-	-	-	(23)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	-	-	-	-	18	18
	(673)	(301)	1,087	10	(247)	(124)
Tax impact						
Income tax on amounts retained in AOCI	231	31	-	-	74	336
Income tax on amounts reclassified to earnings	(45)	-	-	-	(3)	(48)
	186	31	-	-	71	288
Balance at December 31, 2014	(488)	108	309	(5)	(359)	(435)

1 *Reported within Interest expense in the Consolidated Statements of Earnings.*
2 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
3 *Reported within Other expense in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
5 *These components are included in the computation of net periodic pension costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

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

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

Foreign Exchange Risk

The Company generates certain revenues, incurs expenses, and holds a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

The Company has implemented a policy whereby, at a minimum, it hedges a level of foreign currency denominated earnings exposures over a five year forecast horizon. A combination of qualifying and non-qualifying derivative instruments is used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. The Company hedges certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk

The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 2.0%.

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 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 3.4%.

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

Commodity Price Risk

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

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The

Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, RSU. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges as at December 31, 2015 or 2014.

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

December 31, 2015	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
Foreign exchange contracts	**6**	**2**	**2**	**10**	**(3)**	**7**
Interest rate contracts	**2**	**-**	**-**	**2**	**(2)**	**-**
Commodity contracts	**7**	**-**	**772**	**779**	**(211)**	**568**
Other contracts	**-**	**-**	**-**	**-**	**-**	**-**
	15	**2**	**774**	**791**	**(216)**	**575**
Deferred amounts and other assets *(Note 13)*						
Foreign exchange contracts	**114**	**4**	**10**	**128**	**(127)**	**1**
Interest rate contracts	**18**	**-**	**-**	**18**	**(14)**	**4**
Commodity contracts	**7**	**-**	**220**	**227**	**(77)**	**150**
Other contracts	**-**	**-**	**-**	**-**	**-**	**-**
	139	**4**	**230**	**373**	**(218)**	**155**
Accounts payable and other *(Note 16)*						
Foreign exchange contracts	**(1)**	**(106)**	**(765)**	**(872)**	**3**	**(869)**
Interest rate contracts	**(379)**	**-**	**(185)**	**(564)**	**2**	**(562)**
Commodity contracts	**-**	**-**	**(501)**	**(501)**	**194**	**(307)**
Other contracts	**(2)**	**-**	**(6)**	**(8)**	**-**	**(8)**
	(382)	**(106)**	**(1,457)**	**(1,945)**	**199**	**(1,746)**
Other long-term liabilities *(Note 18)*						
Foreign exchange contracts	**-**	**(252)**	**(2,796)**	**(3,048)**	**127**	**(2,921)**
Interest rate contracts	**(405)**	**-**	**(224)**	**(629)**	**14**	**(615)**
Commodity contracts	**-**	**-**	**(260)**	**(260)**	**77**	**(183)**
Other contracts	**(8)**	**-**	**(5)**	**(13)**	**-**	**(13)**
	(413)	**(252)**	**(3,285)**	**(3,950)**	**218**	**(3,732)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**119**	**(352)**	**(3,549)**	**(3,782)**	**-**	**(3,782)**
Interest rate contracts	**(764)**	**-**	**(409)**	**(1,173)**	**-**	**(1,173)**
Commodity contracts	**14**	**-**	**231**	**245**	**(17)**[1]	**228**
Other contracts	**(10)**	**-**	**(11)**	**(21)**	**-**	**(21)**
	(641)	**(352)**	**(3,738)**	**(4,731)**	**(17)**	**(4,748)**

December 31, 2014	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other *(Note 7)*						
Foreign exchange contracts	3	7	3	13	(13)	-
Interest rate contracts	8	-	-	8	(7)	1
Commodity contracts	34	-	501	535	(130)	405
Other contracts	4	-	8	12	-	12
	49	7	512	568	(150)	418
Deferred amounts and other assets *(Note 13)*						
Foreign exchange contracts	33	18	-	51	(51)	-
Interest rate contracts	5	-	-	5	(5)	-
Commodity contracts	17	-	118	135	(43)	92
Other contracts	5	-	3	8	-	8
	60	18	121	199	(99)	100
Accounts payable and other *(Note 16)*						
Foreign exchange contracts	(3)	(80)	(218)	(301)	13	(288)
Interest rate contracts	(438)	-	-	(438)	7	(431)
Commodity contracts	-	-	(281)	(281)	97	(184)
	(441)	(80)	(499)	(1,020)	117	(903)
Other long-term liabilities *(Note 18)*						
Foreign exchange contracts	-	(49)	(1,147)	(1,196)	51	(1,145)
Interest rate contracts	(576)	-	-	(576)	5	(571)
Commodity contracts	-	-	(306)	(306)	43	(263)
	(576)	(49)	(1,453)	(2,078)	99	(1,979)
Total net derivative asset/(liability)						
Foreign exchange contracts	33	(104)	(1,362)	(1,433)	-	(1,433)
Interest rate contracts	(1,001)	-	-	(1,001)	-	(1,001)
Commodity contracts	51	-	32	83	(33)[1]	50
Other contracts	9	-	11	20	-	20
	(908)	(104)	(1,319)	(2,331)	(33)	(2,364)

1 *Amount available for offset includes $17 million (2014 - $33 million) of cash collateral.*

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

December 31, 2015	2016	2017	2018	2019	2020	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**172**	**413**	**2**	**2**	**2**	**-**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**3,059**	**3,213**	**3,133**	**2,630**	**2,303**	**787**
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	**70**	**77**	**6**	**-**	**-**	**-**
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**-**	**-**	**-**	**89**	**25**	**144**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**8,382**	**7,604**	**4,536**	**1,574**	**156**	**406**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**4,291**	**3,371**	**1,960**	**773**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**51**	**48**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(126)**	**(209)**	**(17)**	**2**	**1**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**(6)**	**(17)**	**(9)**	**-**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(5)**	**1**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**40**	**40**	**30**	**31**	**35**	**(35)**

December 31, 2014	2015	2016	2017	2018	2019	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	240	25	413	2	2	2
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	3,203	2,470	2,832	3,100	2,441	2,901
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	15	-	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	5,767	5,486	4,851	3,529	222	469
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	3,528	1,762	2,470	1,176	-	-
Equity contracts *(millions of Canadian dollars)*	41	51	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	(62)	(10)	(25)	(1)	-	-
Commodity contracts - crude oil *(millions of barrels)*	3	(18)	(18)	(9)	-	-
Commodity contracts - NGL *(millions of barrels)*	(5)	-	-	-	-	-
Commodity contracts - power *(MWH)*	25	40	40	30	31	-

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

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

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**77**	8
Interest rate contracts	**(275)**	(1,086)
Commodity contracts	**9**	50
Other contracts	**(47)**	13
Net investment hedges		
Foreign exchange contracts	**(248)**	(113)
	(484)	(1,128)
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*		
Foreign exchange contracts[1]	**9**	8
Interest rate contracts[2]	**128**	101
Commodity contracts[3]	**(46)**	4
Other contracts[4]	**28**	(7)
	119	106
De-designation of qualifying hedges in connection with the Canadian Restructuring Plan *(Note 1)*		
Interest rate contracts[2,5]	**338**	-
	338	-
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**21**	216
Commodity contracts[3]	**5**	(6)
	26	210

1 *Reported within Transportation and other services revenues and Other expense in the Consolidated Statements of Earnings.*
2 *Reported within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Transportation and other services revenues, Commodity sales revenues, Commodity costs and Operating and administrative expense in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*
5 *The amounts above include $338 million relating to the de-designation of qualifying hedges in connection with the Canadian Restructuring Plan.*

The Company estimates that $71 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 48 months as at December 31, 2015.

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.

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Foreign exchange contracts[1]	**(2,187)**	(936)
Interest rate contracts[2]	**(363)**	4
Commodity contracts[3]	**199**	1,031
Other contracts[4]	**(22)**	7
Total unrealized derivative fair value gains/(loss)	**(2,373)**	106

1 *Reported within Transportation and other services revenues (2015 - $1,383 million loss; 2014 - $496 million loss) and Other expense (2015 - $804 million loss; 2014 - $440 million loss) in the Consolidated Statements of Earnings.*

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

3 *Reported within Transportation and other services revenues (2015 - $328 million gain; 2014 - $741 million gain), Commodity sales (2015 - $226 million loss; 2014 - nil), Commodity costs (2015 - $99 million gain; 2014 - $303 million gain) and Operating and administrative expense (2015 - $2 million loss; 2014 - $13 million loss) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2015. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

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

December 31,	**2015**	2014
(millions of Canadian dollars)		
Canadian financial institutions	**47**	58
United States financial institutions	**450**	240
European financial institutions	**95**	73
Asian financial institutions	**4**	-
Other[1]	**213**	310
	809	681

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

As at December 31, 2015, the Company had provided letters of credit totalling $166 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held $17 million of cash collateral on derivative asset exposures at December 31, 2015 and $33 million of cash collateral at December 31, 2014.

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

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

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

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

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

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

Fair Value of Derivatives

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

December 31, 2015	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**10**	**-**	**10**
Interest rate contracts	**-**	**2**	**-**	**2**
Commodity contracts	**14**	**210**	**555**	**779**
Other contracts	**-**	**-**	**-**	**-**
	14	**222**	**555**	**791**
Long-term derivative assets				
Foreign exchange contracts	**-**	**128**	**-**	**128**
Interest rate contracts	**-**	**18**	**-**	**18**
Commodity contracts	**-**	**121**	**106**	**227**
Other contracts	**-**	**-**	**-**	**-**
	-	**267**	**106**	**373**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(872)**	**-**	**(872)**
Interest rate contracts	**-**	**(564)**	**-**	**(564)**
Commodity contracts	**(3)**	**(130)**	**(368)**	**(501)**
Other contracts	**-**	**(8)**	**-**	**(8)**
	(3)	**(1,574)**	**(368)**	**(1,945)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(3,048)**	**-**	**(3,048)**
Interest rate contracts	**-**	**(629)**	**-**	**(629)**
Commodity contracts	**-**	**(21)**	**(239)**	**(260)**
Other contracts	**-**	**(13)**	**-**	**(13)**
	-	**(3,711)**	**(239)**	**(3,950)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(3,782)**	**-**	**(3,782)**
Interest rate contracts	**-**	**(1,173)**	**-**	**(1,173)**
Commodity contracts	**11**	**180**	**54**	**245**
Other contracts	**-**	**(21)**	**-**	**(21)**
	11	**(4,796)**	**54**	**(4,731)**

December 31, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	13	-	13
Interest rate contracts	-	8	-	8
Commodity contracts	62	140	333	535
Other contracts	-	12	-	12
	62	173	333	568
Long-term derivative assets				
Foreign exchange contracts	-	51	-	51
Interest rate contracts	-	5	-	5
Commodity contracts	-	22	113	135
Other contracts	-	8	-	8
	-	86	113	199
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(301)	-	(301)
Interest rate contracts	-	(438)	-	(438)
Commodity contracts	(28)	(137)	(116)	(281)
	(28)	(876)	(116)	(1,020)
Long-term derivative liabilities				
Foreign exchange contracts	-	(1,196)	-	(1,196)
Interest rate contracts	-	(576)	-	(576)
Commodity contracts	-	(125)	(181)	(306)
	-	(1,897)	(181)	(2,078)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(1,433)	-	(1,433)
Interest rate contracts	-	(1,001)	-	(1,001)
Commodity contracts	34	(100)	149	83
Other contracts	-	20	-	20
	34	(2,514)	149	(2,331)

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

December 31, 2015	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	(2)	Forward gas price	2.89	4.26	3.53	\$/mmbtu[3]
NGL	8	Forward NGL price	0.21	1.28	0.87	\$/gallon
Power	(148)	Forward power price	30.00	73.76	53.44	\$/MWH
Commodity contracts - physical[1]						
Natural gas	(69)	Forward gas price	2.04	5.69	3.14	\$/mmbtu[3]
Crude	132	Forward crude price	28.59	87.40	51.71	\$/barrel
NGL	3	Forward NGL price	0.21	1.67	0.74	\$/gallon
Commodity options[2]						
Crude	51	Option volatility	26%	37%	32%	
NGL	79	Option volatility	13%	74%	34%	
	54					

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

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

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

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**149**	(164)
Total gains/(loss)		
Included in earnings[1]	**136**	252
Included in OCI	**(1)**	32
Settlements	**(230)**	29
Level 3 net derivative asset at end of period	**54**	149

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

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at December 31, 2015 or 2014.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totalled $126 million at December 31, 2015 (2014 - $99 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $344 million as at December 31, 2015 (2014 - $323 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. As at December 31, 2015, the fair value of this preferred share investment approximates its face value of $580 million (2014 - $580 million).

As at December 31, 2015, the Company's long-term debt had a carrying value of $41,381 million (2014 - $34,311 million) and a fair value of $41,045 million (2014 - $36,637 million).

NET INVESTMENT HEDGES

The Company has designated a portion of its United States dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of its net investment in United States dollar denominated investments and subsidiaries.

During the year ended December 31, 2015, the Company recognized an unrealized foreign exchange loss on the translation of United States dollar denominated debt of $631 million (2014 - unrealized loss of $199 million) and an unrealized loss on the change in fair value of its outstanding foreign exchange forward contracts of $250 million (2014 - unrealized loss of $114 million) in OCI. The Company also recognized a realized gain of $4 million (2014 - realized gain of $10 million) in OCI associated with the settlement of foreign exchange forward contracts and a realized loss of $75 million (2014 - nil) in OCI associated with the settlement of United States dollar denominated debt that had matured during the period. There was no ineffectiveness during the year ended December 31, 2015 (2014 - nil).

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Earnings before income taxes and discontinued operations	**11**	2,173
Canadian federal statutory income tax rate	**15%**	15%
Expected federal taxes at statutory rate	**2**	326
Increase/(decrease) resulting from:		
Provincial and state income taxes[1]	**(204)**	(36)
Foreign and other statutory rate differentials	**310**	394
Effects of rate-regulated accounting[2]	**(52)**	(97)
Foreign allowable interest deductions	**(84)**	(65)
Part VI.1 tax, net of federal Part I deduction	**55**	47
Intercompany sale of investment[3]	**23**	68
Valuation allowance[4]	**154**	2
Noncontrolling interests	**(28)**	(28)
Other[5]	**(6)**	-
Income taxes on earnings before discontinued operations	**170**	611
Effective income tax rate	**1,545.5%**	28.1%

1 *The higher provincial and state income tax recovery in 2015 reflected the decrease in earnings largely in the Company's Canadian operations due to the depreciation in the Canadian dollar value against the U.S. dollar.*

2 *The amount in 2015 included the federal component of the tax effect of the write-off of regulatory receivables.*

3 *In September 2015 and November 2014, Enbridge sold certain assets to entities under common control. The intercompany gains realized on these transfers were eliminated. However, because these transactions involved the sale of partnership units, tax consequences have been recognized in earnings. This resulted in a tax expense of $39 million and $157 million in 2015 and 2014, respectively.*

4 *The amount in 2015 represents the federal component of the tax effect of a valuation allowance on the deferred tax assets related to an outside basis temporary difference that is no longer more likely than not to be realized.*

5 *2015 included $17 million recovery related to the federal component of the tax effect of adjustments related to prior periods.*

COMPONENTS OF PRETAX EARNINGS AND INCOME TAXES

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Earnings before income taxes and discontinued operations		
Canada	**(1,365)**	114
United States	**808**	1,614
Other	**568**	445
	11	2,173
Current income taxes		
Canada	**157**	35
United States	**3**	(15)
Other	**3**	4
	163	24
Deferred income taxes		
Canada	**(558)**	(193)
United States	**565**	780
	7	587
Income taxes on earnings before discontinued operations	**170**	611

COMPONENTS OF DEFERRED INCOME TAXES

Deferred tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities are as follows:

December 31,	**2015**	2014
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(3,423)**	(2,668)
Investments	**(3,024)**	(2,469)
Regulatory assets	**(354)**	(240)
Other	**(85)**	(102)
Total deferred income tax liabilities	**(6,886)**	(5,479)
Deferred income tax assets		
Financial instruments	**1,374**	644
Pension and OPEB plans	**202**	203
Loss carryforwards	**848**	390
Other	**274**	246
Total deferred income tax assets	**2,698**	1,483
Less valuation allowance	**(538)**	(42)
Total deferred income tax assets, net	**2,160**	1,441
Net deferred income tax liabilities	**(4,726)**	(4,038)
Presented as follows:		
Accounts receivable and other *(Note 7)*	**367**	245
Deferred income taxes	**839**	561
Total deferred income tax assets	**1,206**	806
Accounts payable and other	**(17)**	(2)
Deferred income taxes	**(5,915)**	(4,842)
Total deferred income tax liabilities	**(5,932)**	(4,844)
Net deferred income tax liabilities	**(4,726)**	(4,038)

Valuation allowances have been established for certain loss and credit carryforwards, and outside basis temporary differences on investments that reduce deferred income tax assets to an amount that will more likely than not be realized.

As at December 31, 2015, the Company recognized the benefit of unused tax loss carryforwards of $1,754 million (2014 - $826 million) in Canada which start to expire in 2025 and beyond.

As at December 31, 2015, the Company recognized the benefit of unused tax loss carryforwards of $899 million (2014 - $394 million) in the United States which start to expire in 2030 and beyond.

The Company has not provided for deferred income taxes on the difference between the carrying value of substantially all of its foreign subsidiaries and their corresponding tax basis as the earnings of those subsidiaries are intended to be permanently reinvested in their operations. As such these investments are not anticipated to give rise to income taxes in the foreseeable future. The difference between the carrying values of the investments and their tax bases is largely a result of unremitted earnings and currency translation adjustments. The unremitted earnings and currency translation adjustment for which no deferred taxes have been recognized in respect of foreign subsidiaries is $4.0 billion (2014 - $4.7 billion). If such earnings are remitted, in the form of dividends or otherwise, the Company may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is not practicable.

The Company and one or more of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Company is subject to potential examinations include the United States (Federal and Texas) and Canada (Federal, Alberta and Ontario). The Company’s 2008 to 2015 taxation years are still open for audit in the Canadian and United States jurisdictions. The Company is currently under examination for income tax matters in Canada for the 2011 and 2012 taxation years, and in the United States for the 2009 to 2013 taxation years. The Company is not currently under examination for income tax matters in any other jurisdiction where it is subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**51**	46
Gross increases for tax positions of current year	**5**	5
Reduction for lapse of statute of limitations	**-**	(5)
Change in translation of foreign currency	**9**	5
Unrecognized tax benefits at end of year	**65**	51

The unrecognized tax benefits as at December 31, 2015, if recognized, would affect the Company's effective income tax rate. The Company does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its consolidated financial statements.

The Company recognizes accrued interest and penalties related to unrecognized tax benefits as a component of Income taxes. Income tax expense for the year ended December 31, 2015 included $2 million expense (2014 - nil) of interest and penalties. As at December 31, 2015, interest and penalties of $7 million (2014 - $5 million) have been accrued.

26. RETIREMENT AND POSTRETIREMENT BENEFITS

PENSION PLANS

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 Canadian Plans provide Company funded defined benefit pension and/or defined contribution benefits to Canadian employees of Enbridge. The United States Plan provides Company funded defined benefit pension benefits for United States based employees. The Company has four supplemental pension plans that provide pension benefits in excess of the basic plans for certain employees.

A measurement date of December 31, 2015 was used to determine the plan assets and accrued benefit obligation for the Canadian and United States plans.

Defined Benefit Plans

Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. In 2014, the mortality assumption was revised for the United States Plan resulting in an increase to pension liabilities of $21 million. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations for the basic plans are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Canadian Plans		
Liquids Pipelines	December 31, 2014	December 31, 2015
Gas Distribution	December 31, 2013	December 31, 2016
United States Plan	January 1, 2015	January 1, 2016

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

OTHER POSTRETIREMENT BENEFITS
OPEB primarily includes supplemental health and dental, health spending accounts and life insurance coverage for qualifying retired employees.

BENEFIT OBLIGATIONS AND FUNDED STATUS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plans using the accrual method.

	Pension		OPEB	
December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**2,470**	1,903	**276**	240
Service cost	**167**	108	**8**	8
Interest cost	**98**	93	**11**	12
Employees' contributions	**-**	-	**1**	1
Actuarial (gains)/loss	**(172)**	411	**9**	16
Benefits paid	**(90)**	(75)	**(12)**	(9)
Effect of foreign exchange rate changes	**79**	31	**21**	8
Other	**(1)**	(1)	**(6)**	-
Benefit obligation at end of year	**2,551**	2,470	**308**	276
Change in plan assets				
Fair value of plan assets at beginning of year	**2,062**	1,799	**99**	81
Actual return on plan assets	**88**	179	**(2)**	7
Employer's contributions	**116**	138	**10**	11
Employees' contributions	**-**	-	**1**	1
Benefits paid	**(90)**	(75)	**(12)**	(9)
Effect of foreign exchange rate changes	**54**	22	**19**	8
Other	**(1)**	(1)	**-**	-
Fair value of plan assets at end of year[1]	**2,229**	2,062	**115**	99
Underfunded status at end of year	**(322)**	(408)	**(193)**	(177)
Presented as follows:				
Deferred amounts and other assets	**6**	5	**2**	-
Accounts payable and other	**-**	-	**(6)**	(6)
Other long-term liabilities *(Note 18)*	**(328)**	(413)	**(189)**	(171)
	(322)	(408)	**(193)**	(177)

1 Assets of $40 million (2014 - $32 million) are held by the Company in trust accounts that back non-registered supplemental pension plans benefitting United States plan participants. Due to United States tax regulations, these assets are not restricted from creditors, and therefore the Company is unable to include these balances in plan assets for accounting purposes. However, these assets are committed for the future settlement of non-registered supplemental pension plan obligations included in the underfunded status as at the end of the year.

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
Discount rate	**4.2%**	4.0%	**4.2%**	3.9%
Average rate of salary increases	**3.6%**	4.0%		

NET BENEFIT COSTS RECOGNIZED

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Benefits earned during the year	**167**	108	**8**	8
Interest cost on projected benefit obligations	**98**	93	**11**	12
Expected return on plan assets	**(142)**	(123)	**(6)**	(5)
Amortization of prior service costs	**-**	-	**-**	-
Amortization of actuarial loss	**49**	28	**1**	-
Net defined benefit costs on an accrual basis	**172**	106	**14**	15
Defined contribution benefit costs	**4**	4	**-**	-
Net benefit cost recognized in Earnings	**176**	110	**14**	15
Amount recognized in OCI:				
Net actuarial (gains)/loss[1]	**(107)**	232	**16**	15
Net prior service cost/(credit)[2]	-	-	**(6)**	-
Total amount recognized in OCI	**(107)**	232	**10**	15
Total amount recognized in Comprehensive income	**69**	342	**24**	30

1 Unamortized actuarial losses included in AOCI, before tax, were $404 million (2014 - $489 million) relating to the pension plans and $44 million (2014 - $26 million) relating to OPEB at December 31, 2015.

2 Unamortized prior service credits included in AOCI, before tax, were $1 million (2014 - $6 million costs) relating to OPEB at December 31, 2015.

The Company estimates that approximately $35 million related to pension plans and $1 million related to OPEB at December 31, 2015 will be reclassified from AOCI into earnings in the next 12 months.

Regulatory adjustments are recorded in the Consolidated Statements of Earnings, the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Financial Position to reflect the difference between pension expense for accounting purposes and pension expense for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension or OPEB costs or gains are expected to be collected from or refunded to customers in future rates *(Note 5)*. For the year ended December 31, 2015, an offsetting regulatory asset of nil (2014 - $3 million regulatory liability) has been recorded to the extent pension and OPEB costs are expected to be collected from customers in future rates.

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
Discount rate	**4.0%**	5.0%	**3.9%**	4.9%
Average rate of return on plan assets	**6.7%**	6.7%	**6.0%**	6.0%
Average rate of salary increases	**4.0%**	3.7%		

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	6.7%	4.4%	2034
Other medical	4.5%	-	-
United States Plan	7.0%	4.5%	2037

A 1% increase in the assumed medical care trend rate would result in an increase of $37 million in the benefit obligation and an increase of $2 million in benefit and interest costs. A 1% decrease in the assumed medical care trend rate would result in a decrease of $31 million in the benefit obligation and a decrease of $2 million in benefit and interest costs.

PLAN ASSETS

The Company manages the investment risk of its pension funds by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long-term expectations.

Expected Rate of Return on Plan Assets

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
Canadian Plans	**6.7%**	6.7%		
United States Plan	**7.2%**	7.2%	**6.0%**	6.0%

Target Mix for Plan Assets

	Canadian Plans		
	Liquids Pipelines Plan	Gas Distribution Plan	United States Plan
Equity securities	62.5%	53.5%	62.5%
Fixed income securities	30.0%	40.0%	30.0%
Other	7.5%	6.5%	7.5%

Major Categories of Plan Assets

Plan assets are invested primarily in readily marketable investments with constraints on the credit quality of fixed income securities. As at December 31, 2015, the pension assets were invested 56.4% (2014 - 57.0%) in equity securities, 31.4% (2014 - 32.2%) in fixed income securities and 12.2% (2014 - 10.8%) in other. The OPEB assets were invested 59.1% (2014 - 58.8%) in equity securities, 40.0% (2014 - 40.2%) in fixed income securities and 0.9% (2014 - 1.0%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $21 million asset (2014 - $4 million asset) and refundable tax assets of $106 million (2014 - $96 million) have been excluded from the table below.

	2015				2014			
December 31,	Level 1[1]	Level 2[2]	Level 3[3]	Total	Level 1[1]	Level 2[2]	Level 3[3]	Total
(millions of Canadian dollars)								
Pension								
Cash and cash equivalents	**37**	**-**	**-**	**37**	42	-	-	42
Fixed income securities								
Canadian government bonds	**131**	**-**	**-**	**131**	121	-	-	121
Corporate bonds and debentures	**5**	**3**	**-**	**8**	4	4	-	8
Canadian corporate bond index fund	**259**	**-**	**-**	**259**	254	-	-	254
Canadian government bond index fund	**201**	**-**	**-**	**201**	198	-	-	198
United States debt index fund	**102**	**-**	**-**	**102**	84	-	-	84
Equity								
Canadian equity securities	**133**	**-**	**-**	**133**	131	-	-	131
United States equity securities	**2**	**-**	**-**	**2**	31	-	-	31
Global equity securities	**106**	**25**	**-**	**131**	11	-	-	11
Canadian equity funds	**253**	**-**	**-**	**253**	255	-	-	255
United States equity funds	**243**	**5**	**-**	**248**	185	36	-	221
Global equity funds	**161**	**148**	**-**	**309**	342	134	-	476
Infrastructure[4]	**-**	**-**	**182**	**182**	-	-	51	51
Real estate[4]	**-**	**-**	**115**	**115**	-	-	81	81
Forward currency contracts	**-**	**(10)**	**-**	**(10)**	-	(1)	-	(1)
OPEB								
Cash and cash equivalents	**2**	**-**	**-**	**2**	1	-	-	1
Fixed income securities								
United States government and government agency bonds	**46**	**-**	**-**	**46**	39	-	-	39
Equity								
United States equity funds	**34**	**-**	**-**	**34**	30	-	-	30
Global equity funds	**34**	**-**	**-**	**34**	27	-	-	27

1 Level 1 assets include assets with quoted prices in active markets for identical assets.
2 Level 2 assets include assets with significant observable inputs.
3 Level 3 assets include assets with significant unobservable inputs.
4 The fair values of the infrastructure and real estate investments are established through the use of valuation models.

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

December 31,	**2015**	2014
(millions of Canadian dollars)		
Balance at beginning of year	**132**	126
Unrealized and realized gains	**44**	26
Purchases and settlements, net	**121**	(20)
Balance at end of year	**297**	132

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2015**	2014	**2015**	2014
(millions of Canadian dollars)				
Total contributions	**116**	138	**10**	11
Contributions expected to be paid in 2016	**118**		**11**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2016	2017	2018	2019	2020	2021-2025
(millions of Canadian dollars)						
Expected future benefit payments	104	110	117	124	132	782

27. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Net foreign currency loss	**(884)**	(400)
Allowance for equity funds used during construction	**2**	3
Interest income on affiliate loans	**20**	20
Interest income	**4**	3
Noverco preferred shares dividend income	**40**	42
Gains on dispositions *(Note 6)*	**94**	38
Other	**22**	28
	(702)	(266)

28. SEVERANCE COSTS

Included in Operating and administrative and Other expense is $42 million and $4 million, respectively, in severance costs related to one-time termination benefits to employees. This resulted from an enterprise-wide reduction of workforce that occurred in November 2015 and affected approximately 5% of the Company's workforce. The amounts are included within Eliminations and Other.

In 2015, $22 million was paid with the remaining $24 million to be paid in 2016 and is included in Accounts payable and other as at December 31, 2015.

29. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2015**	2014
(millions of Canadian dollars)		
Accounts receivable and other	**684**	(91)
Accounts receivable from affiliates	**82**	(176)
Inventory	**(315)**	(186)
Deferred amounts and other assets	**364**	(431)
Accounts payable and other	**(1,454)**	(829)
Accounts payable to affiliates	**(26)**	34
Interest payable	**31**	24
Other long-term liabilities	**(52)**	(66)
	(686)	(1,721)

30. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and unless otherwise noted, are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Vector, a joint venture, contracts the services of Enbridge to operate the pipeline. Amounts for these services, which are charged at cost in accordance with service agreements, were $7 million for the year ended December 31, 2015 (2014 - $7 million).

Certain wholly-owned subsidiaries within the Liquids Pipelines, Gas Distribution, Gas Pipelines and Processing and Energy Services segments, have committed and uncommitted transportation arrangements with several joint venture affiliates that are accounted for using the equity method. Total amounts charged to the Company for transportation services for the year ended December 31, 2015 were $332 million (2014 - $256 million).

A wholly-owned subsidiary within Liquids Pipelines had a lease arrangement with a joint venture affiliate. During the year ended December 31, 2015, expenses related to the lease arrangement totalled $151 million (2014 - $21 million) and were recorded to Operating and administrative expense.

Certain wholly-owned subsidiaries within Gas Distribution and Energy Services segments made natural gas and NGL purchases of $228 million (2014 - $315 million) from several joint venture affiliates during the year ended December 31, 2015.

Natural gas sales of $5 million (2014 - $58 million) were made by certain wholly-owned subsidiaries within the Energy Services segment to several joint venture affiliates during the year ended December 31, 2015.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

Amounts receivable from affiliates include a series of loans to Vector and other affiliates totalling $149 million and $3 million, respectively (2014 - $183 million and nil, respectively), which require quarterly interest payments at annual interest rates ranging from 4% to 12%. These amounts are included in Deferred amounts and other assets.

31. COMMITMENTS AND CONTINGENCIES

COMMITMENTS

At December 31, 2015, Enbridge had commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Purchase of services, pipe and other materials, including transportation	14,025	5,459	1,918	1,205	1,118	1,025	3,300
Capital and operating leases	739	110	103	60	56	51	359
Maintenance agreements	420	46	46	31	25	19	253
Land lease commitments	363	13	13	13	13	13	298
Total	15,547	5,628	2,080	1,309	1,212	1,108	4,210

ENBRIDGE ENERGY PARTNERS, L.P.
As at December 31, 2015, Enbridge holds an approximate 35.7% (2014 - 33.7%) combined direct and indirect economic interest in EEP, which is consolidated with noncontrolling interests.

Lakehead System Lines 6A and 6B Crude Oil Releases
The Lakehead System Lines 6A and 6B Crude Oil Releases narratives below reflect the status of these crude oil releases up to February 19, 2016, the date of the original filing of the Company's consolidated financial statements for the year ended December 31, 2015. For a current description of updates related to these crude oil releases since February 19, 2016, refer to the Company's consolidated financial statements for the three months ended March 31, 2016 filed on May 12, 2016.

Line 6B Crude Oil Release
On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. EEP estimates that approximately 20,000 barrels of crude oil were leaked at the site, a portion of which reached the Kalamazoo River via Talmadge Creek, a waterway that feeds the Kalamazoo River. The released crude oil affected approximately 61 kilometres (38 miles) of shoreline along the Talmadge Creek and Kalamazoo River waterways, including residential areas, businesses, farmland and marshland between Marshall and downstream of Battle Creek, Michigan.

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the United States Environmental Protection Agency (EPA) (the EPA Order) which required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. In February 2015, the EPA acknowledged EEP's completion of the EPA Order. In November 2014, regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). The MDEQ has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

In May 2015, EEP reached a settlement with the MDEQ and the Michigan Attorney General's offices regarding the Line 6B crude oil release. As stipulated in the settlement, EEP agrees to: (1) provide at least 300 acres of wetland through restoration, creation, or banked wetland credits, to remain as wetland in perpetuity; (2) pay US$5 million as mitigation for impacts to the banks, bottomlands, and flow of Talmadge Creek and the Kalamazoo River for the purpose of enhancing the Kalamazoo River watershed and restoring stream flows in the River; (3) continue to reimburse the State of Michigan for costs arising from oversight of EEP activities since the release; and (4) continue monitoring, restoration and invasive species control within state-regulated wetlands affected by the release and associated response activities. The timing of these activities is based upon the work plans approved by the State of Michigan.

As at December 31, 2015, EEP's total cost estimate for the Line 6B crude oil release was US$1.2 billion ($193 million after-tax attributable to Enbridge), which is unchanged since December 31, 2014. As at December 31, 2014, the total cost estimate for the Line 6B crude oil release increased by US$86 million as compared to December 31, 2013. The total cost increase of US$86 million during the year ended December 31, 2014, was primarily related to the MDEQ approved Schedule of Work, completion of the dredge activities near Ceresco and Morrow Lake and estimated civil penalties under the Clean Water Act of the United States (Clean Water Act), as described below under *Legal and Regulatory Proceedings*.

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at December 31, 2015. 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

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. EEP estimates that approximately 9,000 barrels of crude oil were released, of which approximately 1,400 barrels were removed from the pipeline as part of the repair. Some of the released crude oil went onto a roadway, into a storm sewer, a waste water treatment facility and then into a nearby retention pond. All but a small amount of the crude oil was recovered. EEP completed excavation and replacement of the pipeline segment and returned it to service on September 17, 2010.

EEP has completed the cleanup, remediation and restoration of the areas affected by the release. On October 21, 2013, the National Transportation Safety Board publicly posted their final report related to the Line 6A crude oil release which states the probable cause of the crude oil release was erosion caused by a leaking water pipe resulting from an improperly installed third-party water service line below EEP's oil pipeline.

The total estimated cost for the Line 6A crude oil release was approximately US$51 million ($7 million after-tax attributable to Enbridge) before insurance recoveries and excluding fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. As at December 31, 2015, EEP has no remaining estimated liability.

Insurance

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

A majority of the costs incurred in connection with the crude oil release for Line 6B are covered by Enbridge's comprehensive insurance policy that expired on April 30, 2011, which had an aggregate limit of US$650 million for pollution liability for Enbridge and its affiliates. Including EEP's remediation spending through December 31, 2015, costs related to Line 6B exceeded the limits of the coverage available under this insurance policy. Additionally, fines and penalties would not be covered under the existing insurance policy. As at December 31, 2015, EEP has recorded total insurance recoveries of US$547 million ($80 million after-tax attributable to Enbridge) for the Line 6B crude oil release out of the US$650 million aggregate limit. EEP will record receivables for additional amounts it claims for recovery pursuant to its insurance policies during the period it deems recovery to be probable.

In March 2013, EEP and Enbridge filed a lawsuit against the insurer who is disputing recovery eligibility for Line 6B costs. In March 2015, Enbridge reached an agreement with that insurer to submit the claim to binding arbitration which is not scheduled to occur until the fourth quarter of 2016. While the Company believes that those costs are eligible for recovery, there can be no assurance that it will prevail in the arbitration.

Enbridge renewed its comprehensive property and liability insurance programs under which the Company is insured through April 30, 2016 with a liability program aggregate limit of US$860 million, which includes sudden and accidental pollution liability. In the unlikely event multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among Enbridge entities on an equitable basis based on an insurance allocation agreement among Enbridge and its subsidiaries.

Legal and Regulatory Proceedings

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

As at December 31, 2015, included in EEP’s estimated costs related to the Line 6B crude oil release is US$44 million in fines and penalties. Of this amount, US$40 million relates to civil penalties under the Clean Water Act. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$40 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures, when combined with any fine or penalty, could be material. EEP has entered into a tolling agreement with the applicable governmental agencies and discussions with these governmental agencies regarding fines, penalties and injunctive relief are ongoing.

In June 2015, Enbridge reached a separate agreement with the United States (Federal Natural Resources Damages Trustees), State of Michigan (State Natural Resources Damages Trustees), Match-E-Be-Nash-She-Wish Band of the Potawatomi Indians and the Nottawaseppi Huron Band of the Potawatomi Indians, and paid approximately US$4 million that was accrued to cover a variety of projects, including the restoration of 175 acres of oak savanna in Fort Custer State Recreation Area and wild rice beds along the Kalamazoo River.

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 the Illinois state court in connection with this crude oil release. On February 20, 2015, EEP agreed to a consent order releasing it from any claims, liability, or penalties.

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 1,700 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. 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. During the fourth quarter of 2013, EEP received approval from the PHMSA to remove the pressure restrictions and to return to normal operating pressures for a period of 12 months. In December 2014, the PHMSA again considered the status of the pipeline in light of information they acquired throughout 2014. On December 9, 2014, EEP received a letter from the PHMSA approving its request to continue the normal operation of Line 14 without pressure restrictions. EEP has no remaining estimated liability for this release.

AUX SABLE

Notice of Violation

In September 2014, Aux Sable US received a Notice and Finding of Violation (NFOV) from the EPA for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable’s Channahon, Illinois facility. As part of the ongoing process of responding to the September 2014 NFOV, Aux Sable discovered what it believes to be an exceedance of currently permitted limits for Volatile Organic Material. Aux Sable received a second NFOV from the EPA in April 2015 in connection with this potential exceedance. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. At this time, the Company is unable to reasonably estimate the financial impact.

TAX MATTERS

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

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

32. GUARANTEES

The Company has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance or to any liabilities relating to a change in laws after December 27, 1991.

The Company has also agreed to indemnify EEM for any tax liability related to EEM's formation, management of EEP and ownership of i-units of EEP. The Company has not made any significant payment under these tax indemnifications. The Company does not believe there is a material exposure at this time.

The Company has also agreed to indemnify the Fund Group for certain liabilities relating to environmental matters arising from operations prior to the transfer of certain assets and interests to the Fund Group in 2012 and prior to the transfer of certain assets and interests to the Fund Group as part of the Canadian Restructuring Plan. The Company has also agreed to pay defined payments to the Fund Group on their investment in Southern Lights in the event shippers do not elect to extend their current contracts post June 2025.

Following the completion of the Canadian Restructuring Plan, EIPLP indirectly owns all of the Class B Units of Southern Lights Canada, together with the Class A Units it already owned. As a result EIPLP holds all the ownership, economic interests and voting rights, direct and indirect, in Southern Lights Canada. The Enbridge guarantee provided in respect of distributions on the Class A Units of Southern Lights Canada was released upon closing of the Canadian Restructuring Plan.

In the normal course of conducting business, the Company enters into agreements which indemnify third parties and affiliates. Examples include indemnifying counterparties pursuant to sale agreements for assets or businesses in matters such as breaches of representations, warranties or covenants, loss or damages to property, environmental liabilities, changes in laws, valuation differences, litigation and contingent liabilities. The Company may indemnify the purchaser for certain tax liabilities incurred while the Company owned the assets or for a misrepresentation related to taxes that result in a loss to the purchaser. Similarly, the Company may indemnify the purchaser of assets for certain tax liabilities related to those assets.

The Company cannot reasonably estimate the maximum potential amounts that could become payable to third parties and affiliates under these agreements; however, historically, the Company has not made any significant payments under indemnification provisions. While these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. The indemnifications and guarantees have not had, and are not reasonably likely to have, a material effect on the Company's financial condition, changes in financial condition, earnings, liquidity, capital expenditures or capital resources.

33. SUBSEQUENT EVENTS

On January 7, 2016, the Company signed an asset purchase and sale agreement to acquire 100% interest in the Tupper Main and Tupper West gas plants and associated pipelines for approximately $538 million. On April 1, 2016, the acquisition closed after the finalization of regulatory approval. The acquired assets are located near Dawson Creek, British Columbia with an aggregate processing capacity of 320 million cubic feet per day of raw gas from the Dawson Creek area Montney field. The transaction will be accounted for as a business combination by applying the acquisition method, and accordingly, the purchase price will be allocated to the assets acquired and liabilities assumed based upon their fair value at the acquisition date. The Company is in the process of finalizing the purchase price allocation.

On March 1, 2016, the Company issued 56,511,000 common shares, inclusive of the shares issued on exercise of the full amount of the underwriters' over-allotment option to purchase an additional 7,371,000 common shares, for gross proceeds of approximately $2.3 billion.

On April 20, 2016, ENF completed a public equity offering of 20.4 million common shares at a price of $28.25 per common share (the Offering Price) for gross proceeds of $575 million. Concurrent with the closing of the equity offering, Enbridge subscribed for 5.1 million common shares at a price of $28.25 per share, for total proceeds of $143 million, on a private placement basis to maintain its 19.9% ownership interest in ENF. ENF used the proceeds from the sale of the common shares to subscribe for additional trust units of the Fund at the Offering Price.