ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2016

GLOSSARY

ACFFO	Available cash flow from operations
ALJ	Administrative Law Judge
Alliance Pipeline Canada	Canadian portion of Alliance Pipeline
Alliance Pipeline US	United States portion of Alliance Pipeline
Average Exchange Rate	United States to Canadian dollar average exchange rate for a period/year
bcf/d	Billion cubic feet per day
bpd	Barrels per day
Cabin	Cabin Gas Plant
Canadian L3R Program	Canadian portion of the Line 3 Replacement Program
CSR	Corporate Social Responsibility
CTS	Competitive Toll Settlement
EBIT	Earnings before interest and income taxes
ECT	Enbridge Commercial Trust
EELP	Enbridge Energy, Limited Partnership
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
EGNB	Enbridge Gas New Brunswick Inc.
EIPLP	Enbridge Income Partners LP
Enbridge or the Company	Enbridge Inc.
ENF	Enbridge Income Fund Holdings Inc.
EPAI	Enbridge Pipelines (Athabasca) Inc.
EPI	Enbridge Pipelines Inc.
Federal Court	Federal Court of Appeal
FERC	Federal Energy Regulatory Commission
Flanagan South	Flanagan South Pipeline
GHG	Greenhouse gas
GP	General partner
GTA	Greater Toronto Area
Heidelberg Pipeline	Heidelberg Oil Pipeline
IDR	Incentive Distribution Rights
IJT	International Joint Tariff
L3R Program	Line 3 Replacement Program
Lakehead System	Lakehead Pipeline System
LNG	Liquefied natural gas
MD&A	Management’s Discussion and Analysis
MEP	Midcoast Energy Partners, L.P.
MNPUC	Minnesota Public Utilities Commission
MPC	Marathon Petroleum Corporation
MW	Megawatts
NEB	National Energy Board
NGL	Natural gas liquids
Norlite	Norlite Pipeline System
Northern Gateway	Northern Gateway Project

Noverco	Noverco Inc.
Offshore	Enbridge Offshore Pipelines
ORM Plan	Operational Risk Management Plan
PPA(s)	Power purchase agreement(s)
Rampion Project	Rampion Offshore Wind Project
RGP	Rich Gas Premium
ROE	Return on equity
Seaway Pipeline	Seaway Crude Pipeline System
Spectra Energy	Spectra Energy Corp
Stampede Pipeline	Stampede Oil Pipeline
the Certificate(s)	Certificate(s) of Public Convenience and Necessity under the authority of the NEB
the Fund	Enbridge Income Fund
the Fund Group	The Fund, ECT, EIPLP and the subsidiaries and investees of EIPLP
the Tupper Plants	Tupper Main and Tupper West gas plants
U.S. GAAP	Generally accepted accounting principles in the United States of America
U.S. L3R Program	United States portion of the Line 3 Replacement Program
Vector	Vector Pipeline
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 17, 2017 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) for the year ended December 31, 2016, prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

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.

On May 12, 2016, the Company filed an amended MD&A for the year ended December 31, 2015 to retrospectively apply the revisions to its reportable segments to the 2015 annual MD&A of the Company that was previously filed on February 19, 2016. Revisions to the segmented information presentation included:

- 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; and
- Presenting the Earnings before interest and income taxes (EBIT) of each segment as opposed to Earnings attributable to Enbridge 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 for the years ended December 31, 2015 and 2014.

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 approximately 3,500 megawatts (MW) (2,500 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 approximately 9,200 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 Alliance Pipeline, 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, Indiana and West Virginia. The Company also has assets under development located in Europe.

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 various pipeline systems.

ELIMINATIONS AND OTHER
In addition to the segments noted above, 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.

MERGER AGREEMENT WITH SPECTRA ENERGY

On September 6, 2016 Enbridge and Spectra Energy Corp (Spectra Energy) announced that they had entered into a definitive merger agreement under which Enbridge and Spectra Energy would combine in a stock-for-stock merger transaction (the Merger Transaction), which valued Spectra Energy common stock at approximately $37 billion (US$28 billion), based on the closing price of Enbridge's common shares on September 2, 2016. The final purchase price for the Merger Transaction may vary based on the market price of Enbridge’s common shares at the time the Merger Transaction is completed. There is no assurance when or if the Merger Transaction will be completed.

The combination will create the largest energy infrastructure company in North America and one of the largest globally based on a pro-forma enterprise value of approximately $165 billion (US$127 billion) as measured at the time of the announcement. The new company would have a substantial capital project portfolio, including $26 billion of commercially secured growth projects through 2019 and a $48 billion probability risk-weighted development project portfolio through 2024. Upon closing of the Merger Transaction, the Company expects to further increase its quarterly common share dividend to approximately 15% above the prevailing quarterly rate of $0.530 per common share in 2016. Also, post closing of the Merger Transaction, the combined capital growth program is expected to deliver ongoing dividend growth of 10%-12% per annum through 2024, while maintaining a payout of 50% to 60% of available cash flow from operations (ACFFO).

Under the terms of the Merger Transaction, Spectra Energy shareholders will receive 0.984 shares of the combined company for each share of Spectra Energy common stock they own. Upon completion of the Merger Transaction, Enbridge shareholders are expected to own approximately 57% of the combined company and Spectra Energy shareholders are expected to own approximately 43%. The combined company will be called Enbridge Inc.

The Merger Transaction was unanimously approved by the Boards of Directors of both companies. Shareholders' approval for both companies was received in December 2016 and both companies continue to work to meet closing conditions, and the required regulatory applications are progressing. Clearance has been received from the Canadian Transportation Agency, the Committee on Foreign Investment in the United States and the United States Federal Trade Commission to complete the Merger Transaction. Additionally, the Ontario Energy Board has communicated that it is satisfied the Merger Transaction does not require its approval. As a standard part of the regulatory approval process for transactions of this type, both companies continue to work closely with the Canadian Competition Bureau to expeditiously conclude its review of the Merger Transaction. Subject to this review and other customary conditions, the Merger Transaction is expected to close in the first quarter of 2017.

ASSETS MONETIZATION PLAN

Concurrent with the announcement of the Merger Transaction, the Company stated its intention to divest approximately $2 billion of assets over a twelve-month period to provide for additional financial flexibility. On December 1, 2016, Enbridge Income Partners LP (EIPLP) completed the sale of the South Prairie Region assets to an unrelated party for cash proceeds of $1.08 billion. The proceeds from the sale will be reinvested in the secured growth capital programs of Enbridge Pipelines (Athabasca) Inc. (EPAI), including the Regional Oil Sands Optimization Project and Norlite Pipeline System (Norlite) project. For further details on the South Prairie Region assets that were sold, refer to *Liquids Pipelines – Feeder Pipelines and Other.* Also, during the fourth quarter of 2016, the Company entered into agreements to sell approximately $0.6 billion of additional miscellaneous non-core assets and investments, the full proceeds of which Enbridge expects will be realized before the end of the first quarter of 2017.

UNITED STATES SPONSORED VEHICLE STRATEGY

On May 2, 2016, EEP announced that it was evaluating opportunities to strengthen its business in light of the commodity price environment which was particularly impacting the performance of its natural gas gathering and processing assets. As part of this evaluation, EEP was exploring various strategic alternatives for its investments in Midcoast Operating Partners, L.P. and Midcoast Energy Partners, L.P. (MEP).

On January 27, 2017, Enbridge announced that it had entered into a merger agreement through a wholly-owned subsidiary, whereby it will take private MEP by acquiring all of the outstanding publicly-held common units of MEP. Total consideration to be paid by Enbridge for these units will be approximately US$170 million and the transaction is expected to close in the second quarter of 2017.

In addition, as part of the on-going strategic review of EEP, further joint funding actions with EEP were announced. Specifically, Enbridge and EEP entered into an agreement for the joint funding of the United States portion of the Line 3 Replacement Program (U.S. L3R Program), whereby Enbridge and EEP will fund 99% and 1%, respectively, of the project development and construction cost. Enbridge has reimbursed EEP approximately US$450 million for capital expenditures incurred to date on the project and will fund 99% of the expenditures through construction. For additional information on the U.S. L3R Program, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Line 3 Replacement Program – United States Line 3 Replacement Program (EEP).* EEP will retain an option to acquire up to 40% of U.S. L3R Program at book value, once the project is completed and in service.

EEP also used a portion of the proceeds reimbursed by Enbridge under the U.S. L3R Program joint funding agreement to acquire an additional 15% interest in the cash generating Eastern Access Project pursuant to an existing joint funding agreement for approximately US$360 million. The strategic review of EEP is ongoing and it is currently expected that any resulting actions will be announced early in the second quarter of 2017. Enbridge will continue working closely with EEP on the strategic review, but any of these anticipated actions are not expected to be material to Enbridge's projections.

CANADIAN RESTRUCTURING PLAN

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

The Transaction was 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 advanced the Company's sponsored vehicle strategy and supported Enbridge's 33% dividend increase effective March 1, 2015 and a further 14% dividend increase effective March 1, 2016. The Transaction provided Enbridge with an alternate source of funding for its enterprise wide growth initiatives and enhanced 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, ACFFO, which was introduced in the second quarter of 2015 and continues to be a part of the Company's normal course annual and quarterly reporting of financial performance. 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 established a long-term target dividend payout of 40% to 50% of ACFFO. For impacts on the Company's long-term target payout policy that would result from the Merger Transaction, see *Merger Agreement with Spectra Energy* above*.*

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. In November 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 share 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 price of $28.25 per share. The proceeds from the issuance of the Fund Units are being used to fund the secured growth capital programs of EPAI and EPI. On December 1, 2016, EIPLP completed the sale of the Southern Prairie Region assets for total consideration of $1.08 billion. The proceeds will be used to reduce leverage, fund the Fund Group’s secured growth program and displace planned equity issuances in 2017.

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 at December 31, 2016, Enbridge’s total economic interest in the Fund Group remained at 86.9%. 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 over time.

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.

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 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, 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 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 debt 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. At the time of the transaction, the Fund Group previously owned a 50% investment in the Canadian portion of 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,		
	2016	2015	**2016**	2015	2014
(millions of Canadian dollars, except per share amounts)					
Earnings attributable to common shareholders					
Liquids Pipelines	**1,389**	675	**3,557**	1,806	1,980
Gas Distribution	**150**	111	**492**	455	432
Gas Pipelines and Processing	**24**	69	**171**	(229)	467
Green Power and Transmission	**30**	50	**154**	177	149
Energy Services	**(147)**	92	**(185)**	325	730
Eliminations and Other	**(219)**	(156)	**(148)**	(899)	(456)
Earnings before interest and income taxes	**1,227**	841	**4,041**	1,635	3,302
Interest expense	**(412)**	(371)	**(1,590)**	(1,624)	(1,129)
Income taxes recovery/(expense)	**32**	(94)	**(142)**	(170)	(611)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(406)**	76	**(240)**	410	(203)
Preference share dividends	**(76)**	(74)	**(293)**	(288)	(251)
Earnings/(loss) attributable to common shareholders	**365**	378	**1,776**	(37)	1,108
Discontinued operations - Gas Pipelines and Processing	**-**	-	**-**	-	46
	365	378	**1,776**	(37)	1,154
Earnings/(loss) per common share	**0.39**	0.44	**1.95**	(0.04)	1.39
Diluted earnings/(loss) per common share	**0.39**	0.44	**1.93**	(0.04)	1.37
Adjusted earnings					
Liquids Pipelines	**1,011**	949	**3,958**	3,384	2,592
Gas Distribution	**150**	128	**494**	446	391
Gas Pipelines and Processing	**95**	88	**366**	336	293
Green Power and Transmission	**43**	49	**165**	175	151
Energy Services	**(5)**	(22)	**28**	61	42
Eliminations and Other	**(96)**	(74)	**(349)**	(246)	(60)
Adjusted earnings before interest and income taxes[1]	**1,198**	1,118	**4,662**	4,156	3,409
Interest expense[2]	**(403)**	(372)	**(1,545)**	(1,273)	(926)
Income taxes[2]	**(136)**	(130)	**(520)**	(486)	(434)
Noncontrolling interests and redeemable noncontrolling interests[2]	**(61)**	(48)	**(226)**	(243)	(225)
Discontinued operations	**-**	-	**-**	-	1
Preference share dividends	**(76)**	(74)	**(293)**	(288)	(251)
Adjusted earnings[1]	**522**	494	**2,078**	1,866	1,574
Adjusted earnings per common share[1]	**0.56**	0.58	**2.28**	2.20	1.90
Cash flow data					
Cash provided by operating activities	**1,058**	772	**5,211**	4,571	2,547
Cash provided by/(used in) investing activities	**8**	(2,262)	**(5,192)**	(7,933)	(11,891)
Cash provided by financing activities	**1**	1,457	**1,102**	2,973	9,770
Available cash flow from operations[3]					
Available cash flow from operations	**879**	876	**3,713**	3,154	2,506
Dividends					
Common share dividends declared	**497**	401	**1,945**	1,596	1,177
Dividends paid per common share	**0.530**	0.465	**2.12**	1.86	1.40
Revenues					
Commodity sales	**6,436**	6,074	**22,816**	23,842	28,281
Gas distribution sales	**703**	672	**2,486**	3,096	2,853
Transportation and other services	**2,199**	2,168	**9,258**	6,856	6,507
	9,338	8,914	**34,560**	33,794	37,641
Total assets	**85,832**	84,515	**85,832**	84,515	72,741
Total long-term liabilities	**47,511**	51,362	**47,511**	51,362	42,190

1 *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 18.*

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 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, 2016, EBIT was $4,041 million compared with $1,635 million for the year ended December 31, 2015 and $3,302 million for the year ended December 31, 2014. For the fourth quarter of 2016, EBIT was $1,227 million compared with $841 million for the fourth quarter of 2015.

As discussed below in *Adjusted EBIT*, the Company has continued to deliver strong earnings growth from a majority of its businesses over the course of the last two years, offset partly in the second quarter of 2016 by the impacts of extreme wildfires in northeastern Alberta discussed in *Liquids Pipelines – Impact of Wildfires in Northeastern Alberta*. The positive impact of this growth and the comparability of the Company's earnings for each period are impacted by a number of unusual, non-recurring or non-operating factors that are enumerated in the Non-GAAP Reconciliation tables and discussed in the results for each reporting segment, the most significant of which are summarized below:

- 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. For the year ended December 31, 2016, the Company's EBIT reflected $543 million of unrealized derivative fair value gains, compared with $2,017 million and $36 million of unrealized derivative fair value loss in the corresponding 2015 and 2014 periods.
- EBIT for 2016 reflected an $850 million gain ($520 million after-tax attributable to Enbridge) within the Liquids Pipelines segment related to the disposition of the South Prairie Region assets in December 2016.
- The Company's 2016 EBIT was also impacted by certain impairment charges reflected within the Liquids Pipelines segment. In the fourth quarter of 2016, the Canadian Federal Government directed the National Energy Board (NEB) to dismiss the Company's Northern Gateway Project (Northern Gateway) application and the Certificates of Public Convenience and Necessity under the authority of the NEB (the Certificates) have been rescinded. In consultation with potential shippers and Aboriginal equity partners, the Company assessed this decision and concluded that the project cannot proceed as envisioned. After taking into consideration the amount recoverable from potential shippers on Northern Gateway, the Company reflected an impairment of $373 million ($272 million after-tax) in the fourth quarter of 2016.
- In September 2016, EEP announced that it had applied for the withdrawal of the regulatory applications for the Sandpiper Project that were pending with the Minnesota Public Utilities Commission (MNPUC). In connection with this announcement and other factors, the total impairment charge in respect of the Sandpiper Project recorded during the year, including related project costs of $12 million, was $1,004 million, of which $875 million was attributable to noncontrolling interests in EEP and Marathon Petroleum Corporation (MPC), EEP's partner in the Sandpiper Project ($81 million after-tax in total attributable to Enbridge's common shareholders).
- In the second quarter of 2016, an impairment charge of $176 million ($103 million after-tax attributable to Enbridge) was recorded relating to Enbridge's 75% joint venture interest in Eddystone Rail, a rail-to-barge transloading facility located in the greater Philadelphia, Pennsylvania area that delivers Bakken and other light sweet crude oil to Philadelphia area refineries. Due to a significant decrease in price spreads between Bakken crude oil and West Africa/Brent crude oil and increased competition in the region, demand for Eddystone Rail services dropped significantly, resulting in an impairment of this facility.
- EBIT for 2015 was also impacted by 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 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

For the year ended December 31, 2016, earnings attributable to common shareholders were $1,776 million ($1.95 earnings per common share) compared with a loss of $37 million ($0.04 loss per common share) for the year ended December 31, 2015 and earnings of $1,154 million ($1.39 earnings per common share) for the year ended December 31, 2014.

For the quarter ended December 31, 2016, earnings attributable to common shareholders were $365 million ($0.39 earnings per common share) compared with $378 million ($0.44 earnings per common share) for the quarter ended December 31, 2015.

In addition to the factors discussed in *EBIT* above and in *Adjusted EBIT* and *Adjusted Earnings* below, the year-over-year and fourth quarter-over-quarter comparability of earnings/(loss) attributable to common shareholders was impacted by a number of unusual, non-recurring and non-operating factors that are summarized and described under *Non-GAAP Reconciliation – EBIT to Adjusted Earnings.*

ADJUSTED EBIT

For the year ended December 31, 2016, adjusted EBIT was $4,662 million, compared with adjusted EBIT of $4,156 million for the year ended December 31, 2015. For the fourth quarter ended December 31, 2016, adjusted EBIT was $1,198 million, an increase of $80 million over the corresponding 2015 period.

Growth in consolidated adjusted EBIT year-over-year was largely driven by stronger contributions from the Company's Liquids Pipelines segment which benefitted from a number of new assets that were placed into service in 2015, the most prominent being the expansion of the Company's mainline system in the third quarter of 2015, as well as the reversal and expansion of Line 9B and completion of the Southern Access Extension in the fourth quarter of 2015, which provided increased access to the eastern Canada and Patoka markets, respectively. The Company continued to realize throughput growth on the Canadian Mainline, Lakehead System and Regional Oil Sands System primarily due to strong oil sands production growth in western Canada enabled by recently completed pipeline expansion projects. However, the positive effect of increased production and higher capacity on liquids pipelines throughput was partially negated in the second quarter of 2016 by the impact of extreme wildfires in northeastern Alberta which led to a temporary shutdown of certain of the Company's upstream pipelines and terminal facilities resulting in a disruption of service on Enbridge's Regional Oil Sands System with corresponding impacts into and out of Enbridge's downstream pipelines, including Canadian Mainline and the Lakehead System. Reduced system deliveries resulted in a negative impact of approximately $74 million on the Company's adjusted EBIT for 2016. Growth in Canadian Mainline adjusted EBIT was also partially offset by a combination of a lower average International Joint Tariff (IJT) Residual Benchmark Toll, which decreased effective April 1, 2016, and a lower foreign exchange rate on hedges used to convert Canadian Mainline United States dollar toll revenues to Canadian dollars.

In 2016, the Company also benefitted from stronger adjusted EBIT contributions from the United States Mid-Continent and Gulf Coast systems, attributable to increased transportation revenues mainly resulting from an increase in the level of committed take-or-pay volumes on the Flanagan South Pipeline (Flanagan South). Adjusted EBIT from Feeder Pipelines and Other was also higher, reflecting the benefits of a full year of earnings from Southern Access Extension.

These positive trends on consolidated adjusted EBIT were partially offset by the performance of the United States portion of the Bakken System where adjusted EBIT fell primarily due to a lower surcharge on tolls subject to annual adjustment, as well as lower revenues from EEP's Berthold rail facility as a result of declining volumes on expiry of contracts.

Many of the annual trends discussed above were also factors driving adjusted EBIT growth in the Liquids Pipelines segment in the fourth quarter of 2016, when compared with the fourth quarter of 2015. However, the decrease in Canadian Mainline IJT Residual Benchmark Toll and a lower rate on foreign exchange hedges of United States dollar toll revenue resulted in a decrease in Canadian Mainline adjusted EBIT for the fourth quarter of 2016 compared with the fourth quarter of 2015. In addition, there was a decrease in Mid-Continent and Gulf Coast adjusted EBIT for the fourth quarter of 2016 compared with the corresponding 2015 period, due to a year-over-year decline in demand for services on Spearhead Pipeline.

Within the Gas Distribution segment, EGD, which operates under a five-year customized Incentive Rate Plan approved in 2014, generated higher adjusted EBIT in 2016 primarily due to higher distribution charges arising from growth in EGD's rate base.

The Gas Pipelines and Processing segment benefitted from operational efficiencies achieved by Alliance Pipeline. The Enbridge Offshore Pipelines' (Offshore) Heidelberg Oil Pipeline (Heidelberg Pipeline) which was placed into service in January 2016 and Canadian Midstream's Tupper Main and Tupper West gas plants (the Tupper Plants) which were acquired on April 1, 2016 also contributed to the year-over-year increase in the Gas Pipelines and Processing segment's adjusted EBIT. The positive effects were partially offset by the impact of lower volumes on US Midstream facilities due to reduced drilling by producers.

The Green Power and Transmission segment adjusted EBIT decreased year-over-year as a result of disruptions at certain eastern Canadian wind farms in the first quarter and fourth quarter of 2016 due to weather conditions which caused icing of blades, as well as weaker wind resources experienced at certain facilities in Canada during the first half and fourth quarter of 2016. These negative effects were partially offset by stronger wind resources at the Company's United States wind farms during the second half of 2016.

Within the Energy Services segment, a decrease in adjusted EBIT in 2016 reflected weaker performance from Energy Services' Canadian and United States operations during the first half of 2016. The compression of certain crude oil location and quality differentials and the impact of a weaker NGL market drove a year-over-year decrease in adjusted EBIT. This decrease was partially offset by positive contributions from increased crude oil storage opportunities which also resulted in a lower adjusted loss before interest and income taxes for the fourth quarter of 2016 compared with the corresponding 2015 period.

Within Eliminations and Other, a higher realized foreign exchange derivative loss related to settlements under the Company's foreign exchange risk management program, as well as higher operating and administrative expenses resulted in an increase in year-over-year adjusted loss before interest and income taxes. The realized loss in Eliminations and Other serves to partially offset the positive effect of translating the earnings performance of the United States dollar denominated businesses to Canadian dollars at the prevailing exchange rate, which averaged $1.32 in 2016, and which is reflected in the reported EBIT of the applicable business segments. Operating and administrative expenses, which were higher primarily due to an increase in depreciation expense, resulting from investment in new information technology assets, and lower recoveries from other business segments, also contributed to a higher fourth quarter adjusted loss before interest and income taxes, when compared with the corresponding 2015 period.

For the year ended December 31, 2015, adjusted EBIT was $4,156 million, compared with adjusted EBIT of $3,409 million for the year ended December 31, 2014. The year-over-year 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 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.

ADJUSTED EARNINGS

Adjusted earnings for the year ended December 31, 2016 were $2,078 million ($2.28 per common share) compared with $1,866 million for the year ended December 31, 2015 ($2.20 per common share) and $1,574 million ($1.90 per common share) for the year ended December 31, 2014. Adjusted earnings for the fourth quarter of 2016 were $522 million ($0.56 per common share) compared with $494 million ($0.58 per common share) for the fourth quarter of 2015.

The year-over-year increases in adjusted earnings reflected the operating factors as discussed above in *Adjusted EBIT*. The impacts of extreme wildfires in northeastern Alberta in the second quarter of 2016 on adjusted earnings and adjusted earnings per share for the year ended December 31, 2016 remained unchanged at $26 million and $0.03, respectively.

Partially offsetting the adjusted earnings growth discussed above was higher interest expense over the past two years resulting from debt incurred to fund asset growth and the impact of refinancing construction debt with longer-term debt financing. The amount of interest capitalized year-over-year also decreased as a result of projects coming into service. Preference share dividends were also higher year-over-year resulting from additional preference shares issued in 2014 and in the fourth quarter of 2016 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 an increase in adjusted income taxes expense which resulted from 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.

Adjusted earnings attributable to noncontrolling interests and redeemable noncontrolling interests decreased in 2016 compared with 2015. The decrease was driven by a full year of a lower public ownership interest in the Fund Group following the execution of the Canadian Restructuring Plan in the third quarter of 2015. Adjusted earnings attributable to noncontrolling interests were higher in the fourth quarter of 2016 when compared with the fourth quarter of 2015, due to stronger operating performance at EEP primarily as a result of a stronger contribution from its liquids business.

Despite the increase in the Company's economic interest in the Fund Group in 2015 as a result of the Canadian Restructuring Plan, the adjusted earnings attributable to the Fund Group's redeemable noncontrolling interests increased in 2015 compared with 2014 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*.

AVAILABLE CASH FLOW FROM OPERATIONS

ACFFO was $879 million for the three months ended December 31, 2016 compared with $876 million for the three months ended December 31, 2015. ACFFO was $3,713 million for the year ended December 31, 2016 compared with $3,154 million for the year ended December 31, 2015. The quarter-over-quarter and year-over-year change in ACFFO was impacted by the growth in adjusted EBIT as discussed in *Adjusted EBIT* above, as well as other items discussed below.

Contributing to the year-over-year increase in ACFFO were lower maintenance capital expenditures in 2016 compared with 2015. 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. Maintenance capital expenditures decreased in 2016 as higher expenditures in the Company's Gas Distribution segment were more than offset by lower maintenance capital expenditures in the Liquids Pipelines segment. The lower spending in Liquids Pipelines reflected a shift in the timing of maintenance activities to 2017 on certain leasehold improvements, as well as scope refinements to certain planned maintenance projects resulting from ongoing communication with regulators. The Company plans to continue to invest in its maintenance capital program to support the safety and reliability of its operations.

ACFFO also includes cash distributions from the Company's equity investments. The Company's distributions from such investments in 2016 were higher compared with 2015 and reflected improved performance of such investments, as well as distributions from assets placed into service in recent years.

Other non-cash adjustments include various non-cash items presented in the Company's Consolidated Statements of Cash Flows, as well as adjustments for unearned revenues received in each year.

Partially offsetting the items discussed above, which created period-over-period increases in ACFFO, was higher interest expense as discussed in *Adjusted Earnings* above.

The increase in ACFFO was also partially offset by increased distributions to noncontrolling interests in EEP and to redeemable noncontrolling interests in the Fund Group. A higher per unit distribution and the effects of a strengthening United States dollar versus the Canadian dollar resulted in greater distributions to noncontrolling interests in EEP during the first half of 2016. Higher distributions to redeemable noncontrolling interests in the Fund Group were a result of a higher per unit distribution and increased public ownership in the Fund Group.

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 year-over-year increase in ACFFO was impacted by the growth in adjusted earnings as discussed in *Adjusted EBIT* above. Also contributing to the increase in ACFFO in 2015 compared with 2014 was decrease in maintenance capital expenditures due to the completion of specific maintenance programs in 2014 and higher year-over-year cash distributions received from the Company's equity investments. Partially offsetting these positive effects were higher interest expense and higher preference share dividends, as well as higher current income taxes expense in 2015 primarily attributable to the Company's ability to carry back tax losses in the 2014 taxation year to recover prior year taxes paid. 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 LOW 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.

Benchmark prices for West Texas Intermediate (WTI) crude fell below US$30 per barrel at the beginning of 2016 and have remained volatile as the market seeks to re-balance supply and demand. Prices began to recover throughout the year and have climbed above US$50 per barrel periodically. WTI crude prices averaged US$43 per barrel for 2016 but ended the year above US$53 per barrel. WTI crude prices averaged US$52.50 per barrel in January 2017. 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 of investment in exploration and development programs 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, and in fact, mainline throughput as measured at the Canada/United States border at Gretna, Manitoba saw record throughput of 2.6 million barrels per day (bpd) in the month of December 2016. Also in 2016, the mainline system has continued to be subject to apportionment of heavy crudes, as nominated volumes currently exceed capacity on portions of the system. 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 lower oil prices are 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, including EEP's Sandpiper Project for which regulatory applications were withdrawn in September 2016, Enbridge's most recent near-term supply forecast reaffirms that the expansions and extensions of its liquids pipeline system that were completed in 2015, as well as the projects currently in progress will provide cost-effective transportation services to key markets in North America and will be well utilized.

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 last phase of the Line 6B capacity expansion on EEP's Lakehead System which was placed into service in June 2016. This expansion, which is the final component of the Eastern Access Program, provides increased access to refineries in the upper midwest United States and eastern Canada. In addition, in February 2017, the Company completed the acquisition of a 27.6% equity interest in the Bakken Pipeline System which, upon completion, will further enhance Enbridge's strategy of providing efficient market access solutions for Bakken production while providing the opportunity for the implementation of joint tolls with the Energy Transfer Crude Oil Pipeline, and will also enhance market access opportunities for Enbridge's customers and create a new flow path through the Company's mainline system to the eastern United States Gulf Coast. For recent developments on this matter, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Bakken Pipeline System.*

CASH FLOWS

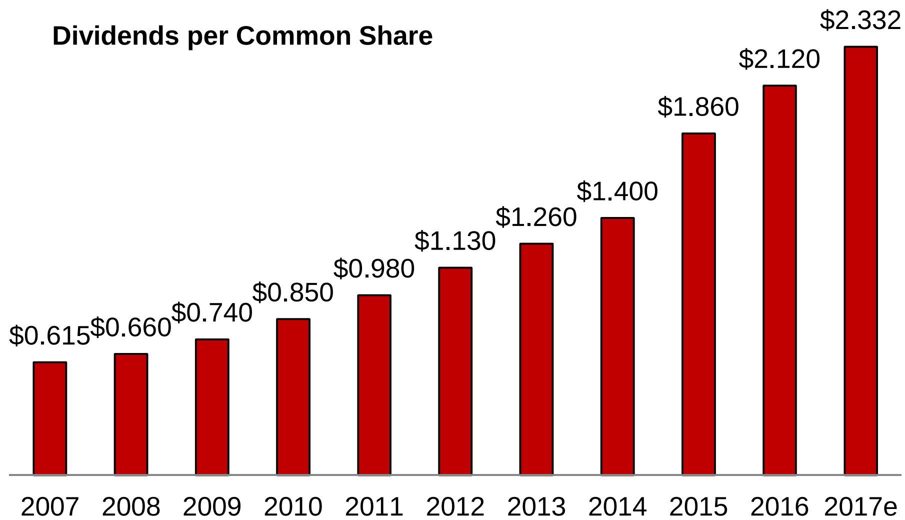
Cash provided by operating activities was $5,211 million for the year ended December 31, 2016, mainly driven by strong operating performance from the Company's core assets, particularly from Liquids Pipelines and the cash flow generated from growth projects placed into service in recent years. Cash provided by operating activities was also impacted by changes in operating assets and liabilities as further discussed in *Liquidity and Capital Resources*.

In 2016, Enbridge completed certain capital market transactions. The funding raised through these transactions, along with additional borrowings from the Company's credit facilities, cash generated from operations and cash on hand, were more than sufficient to finance the Company's $5.1 billion of capital expenditures in 2016. These funding and cash resources are also expected to provide financing flexibility for the Company's growth capital program in 2017.

Highlights of capital market transactions in 2016 include Enbridge's common shares issuance of approximately $2.3 billion in March and the issuance of $750 million preference shares in November. For the first time in over two years, Enbridge also accessed the United States debt markets, issuing in November 2016, two separate US$750 million tranches of senior notes carrying maturity terms of 10 and 30 years, respectively. In December 2016, Enbridge also issued fixed-to-floating subordinated notes of US$750 million with a maturity of 2077. During 2016, Enbridge, through its sponsored vehicles, issued equity of approximately $0.6 billion. Lastly, Enbridge and its subsidiaries issued approximately $1.1 billion in medium-term notes and extended the average maturity of its secured credit facilities. As discussed in *Liquidity and Capital Resources*, the Company continues to utilize its sponsored vehicles to enhance its enterprise-wide funding program. To further provide for additional financial flexibility, the Company continued to advance its plan to divest approximately $2 billion of non-core assets over a twelve-month period as discussed under *Merger Agreement with Spectra Energy – Assets Monetization Plan*. Under this plan, in December 2016, EIPLP completed the sale of the South Prairie Region assets to an unrelated party for cash proceeds of $1.08 billion and the Company also entered into agreements to sell approximately $0.6 billion of additional miscellaneous non-core assets and investments.

DIVIDENDS

The Company has paid common share dividends in every year since it became a publicly traded company in 1953. In January 2017, the Company announced a 10% increase in its quarterly dividend to $0.583 per common share, or $2.332 annualized, effective March 1, 2017.



As described under *Merger Agreement with Spectra Energy,* upon close of the Merger Transaction, the Company expects to further increase its quarterly common share dividend by an amount sufficient to bring the aggregate increase in the quarterly dividend to approximately 15% above the then prevailing quarterly rate of $0.530 per common share in 2016. For the 10-year period ended December 2016, the Company's compound annual average dividend growth rate was 13.9%.

As described under the *Canadian Restructuring Plan*, Enbridge's current target dividend payout policy range is 40% to 50% of ACFFO. In 2016, the dividend payout was 52.0% (2015 - 50.0%) of ACFFO. For expected impacts to the Company's dividend payout policy range as a result of the Merger Transaction, refer to *Merger Agreement with Spectra Energy.*

REVENUES

The Company generates revenues from three primary sources: commodity sales, gas distribution sales and transportation and other services. Commodity sales of $22,816 million for the year ended December 31, 2016 (2015 - $23,842 million; 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, grades 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 the corresponding tolls for transportation services. 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; financial strength and flexibility; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for the Company's commercially secured growth program; expected future growth and expansion opportunities; expectations about the Company's joint venture partners' ability to complete and finance projects under construction; expected closing of acquisitions and dispositions; estimated cost and impact to the Company's overall financial performance of complying with the settlement consent decree related to Line 6B and Line 6A; estimated future dividends; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; the Merger Transaction and expectation regarding the timing and closing thereof; expectations regarding the impact of the Merger Transaction including the combined Company's scale, financial flexibility, growth program, future business prospects and performance; dividend payout policy; dividend growth and dividend payout expectation; expectations on impact of hedging program; strategic alternatives currently being evaluated in connection with the United States sponsored vehicles strategy and the regulatory framework and recovery of deferred costs by Enbridge Gas New Brunswick Inc. (EGNB).

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 timing and completion of the Merger Transaction, including receipt of regulatory approvals and the satisfaction of other conditions precedent; the realization of anticipated benefits and synergies of the Merger Transaction, governmental legislation, acquisitions and the timing thereof; the success of integration plans; cost of complying with the settlement consent decree related to Line 6B and Line 6A; impact of the 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 the impact of the Merger Transaction on the Company, expected EBIT, adjusted EBIT, earnings/(loss), adjusted earnings/(loss) and associated per share amounts, ACFFO or estimated future dividends. The most relevant assumptions associated with forward-looking statements on announced projects and 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, government and regulatory approvals on construction and in-service schedules and cost recovery regimes.*

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to the impact of the Merger Transaction, operating performance, regulatory parameters, dividend policy, project approval and support, renewals of rights of way, weather, economic and competitive conditions, public opinion, changes in tax laws and tax rates, exchange rates, interest rates, commodity prices, political decisions, supply of and demand for commodities and the settlement consent decree related to Line 6B and Line 6A, 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), adjusted earnings/(loss) per common share 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 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), adjusted earnings/(loss) per share and ACFFO gives 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), adjusted earnings/(loss) per common share 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,		
	2016	2015	**2016**	2015	2014
(millions of Canadian dollars)					
Earnings before interest and income taxes	**1,227**	841	**4,041**	1,635	3,302
Adjusting items:[1]					
Change in unrealized derivative fair value (gains)/loss[2]	**277**	79	**(543)**	2,017	36
Sandpiper Project asset impairment[3]	**4**	-	**1,004**	-	-
Gain on sale of South Prairie Region assets	**(850)**	-	**(850)**	-	-
Northern Gateway asset impairment	**373**	-	**373**	-	-
Goodwill impairment loss	**-**	-	**-**	440	-
Assets and investment impairment loss	**56**	88	**253**	108	18
Make-up rights adjustments	**(1)**	50	**130**	42	35
Employee severance and restructuring costs	**52**	41	**82**	41	6
Project development and transaction costs	**56**	2	**86**	44	17
Unrealized intercompany foreign exchange (gains)/loss	**(10)**	(21)	**43**	(131)	(16)
Northeastern Alberta wildfires pipelines and facilities restart costs	**8**	-	**47**	-	-
Warmer/(colder) than normal weather	**10**	22	**18**	(15)	(48)
Hydrostatic testing	**(1)**	23	**(15)**	72	-
Leak remediation costs, net of leak insurance recoveries	**(11)**	(21)	**(8)**	(26)	92
(Gains)/loss on sale of non-core assets and investment, net	**-**	-	**4**	(88)	(38)
Other	**8**	14	**(3)**	17	5
Adjusted earnings before interest and income taxes	**1,198**	1,118	**4,662**	4,156	3,409
Interest expense	**(412)**	(371)	**(1,590)**	(1,624)	(1,129)
Income taxes recovery/(expense)	**32**	(94)	**(142)**	(170)	(611)
(Earnings)/loss attributable to noncontrolling interest and redeemable noncontrolling interests	**(406)**	76	**(240)**	410	(203)
Discontinued operations	**-**	-	**-**	-	46
Preference share dividends	**(76)**	(74)	**(293)**	(288)	(251)
Adjusting items in respect of:					
Interest expense[4]	**9**	(1)	**45**	351	203
Income taxes[5]	**(168)**	(36)	**(378)**	(316)	177
Discontinued operations	**-**	-	**-**	-	(45)
Noncontrolling interests and redeemable noncontrolling interests[6]	**345**	(124)	**14**	(653)	(22)
Adjusted earnings	**522**	494	**2,078**	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.*

3 *Inclusive of $12 million of related project costs.*

4 *Interest expense for each period included changes in unrealized derivative fair value gains and losses on interest rate contracts. For the year ended December 31, 2015, interest expense also included a loss of $338 million on de-designation of interest rate hedges from the transfer of assets between entities under common control of Enbridge in connection with the Canadian Restructuring Plan.*

5 *Income Taxes were impacted by adjustments for unusual, non-recurring and non-operating factors as enumerated under adjusting items for earnings before interest and income taxes. For the year ended December 31, 2016, income taxes also included a recovery of $296 million related to an adjustment for a curing loss as described in footnote 6 below. Adjustments for income taxes also included an out-of-period adjustment of $71 million recognized in the first quarter of 2015 in respect of an overstatement of deferred income taxes expense in 2013 and 2014. In the third quarter of 2015, income taxes included an $88 million write-off of a regulatory asset in respect of taxes in connection with the Canadian Restructuring Plan and a valuation allowance of $176 million in respect of deferred income tax assets related to EEP. For the year ended December 31, 2014, income taxes included an expense of $157 million related tax consequences associated with the sale of partnership units between entities under common control of Enbridge. The intercompany gains realized as a result of the transfer between entities were eliminated for accounting purposes, however all tax consequences have remained in consolidated earnings.*

6 *Noncontrolling interests and redeemable noncontrolling interests were also impacted by adjustments for unusual, non-recurring and non-operating factors as enumerated under adjusting items for earnings before interest and income taxes, as well as adjusting items for interest expense and income taxes. Under EEP's partnership agreement, capital deficits cannot be accumulated in the capital account of any limited partner and thus, such capital account deficits are brought to zero or "cured". For the year ended December 31, 2016 , the book value of limited partnership capital accounts in EEP became negative, resulting in a reallocation of such deficit to the Company's general partnership account in EEP. For the year ended December 31, 2016, earnings attributable to noncontrolling interests were higher by $816 million due to such reallocation. In the case of any additional losses or unanticipated charges to EEP in future periods, curing may occur in such periods.*

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,		
	2016	2015	**2016**	2015	2014
(millions of Canadian dollars)					
Adjusted earnings before interest and income taxes	**1,198**	1,118	**4,662**	4,156	3,409
Depreciation and amortization[1]	**564**	541	**2,240**	2,024	1,577
Maintenance capital[2]	**(205)**	(200)	**(671)**	(720)	(970)
	1,557	1,459	**6,231**	5,460	4,016
Interest expense[3]	**(403)**	(372)	**(1,545)**	(1,273)	(926)
Current income taxes[3]	**(31)**	(53)	**(92)**	(160)	(12)
Distributions to noncontrolling interests	**(182)**	(179)	**(720)**	(680)	(535)
Distributions to redeemable noncontrolling interests	**(54)**	(34)	**(202)**	(114)	(79)
Preference share dividends	**(76)**	(74)	**(293)**	(288)	(245)
Cash distributions in excess of equity earnings[3]	**67**	64	**183**	244	196
Other non-cash adjustments	**1**	65	**151**	(35)	91
Available cash flow from operations (ACFFO)	**879**	876	**3,713**	3,154	2,506
1 Depreciation and amortization:					
Liquids Pipelines	***344***	*336*	***1,369***	*1,227*	*911*
Gas Distribution	***88***	*78*	***339***	*308*	*304*
Gas Pipelines and Processing	***70***	*70*	***292***	*272*	*221*
Green Power and Transmission	***48***	*47*	***190***	*186*	*124*
Energy Services	***1***	*-*	***2***	*(1)*	*(2)*
Eliminations and Other	***13***	*10*	***48***	*32*	*19*
	564	*541*	***2,240***	*2,024*	*1,577*
2 Maintenance capital:					
Liquids Pipelines	***(76)***	*(44)*	***(207)***	*(278)*	*(500)*
Gas Distribution	***(88)***	*(118)*	***(339)***	*(302)*	*(296)*
Gas Pipelines and Processing	***(17)***	*(17)*	***(48)***	*(45)*	*(62)*
Green Power and Transmission	***(2)***	*-*	***(5)***	*-*	*(1)*
Eliminations and Other	***(22)***	*(21)*	***(72)***	*(95)*	*(111)*
	(205)	*(200)*	***(671)***	*(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,		
	2016	2015	**2016**	2015	2014
(millions of Canadian dollars)					
Cash provided by operating activities - continuing operations	**1,058**	772	**5,211**	4,571	2,528
Adjusted for changes in operating assets and liabilities[1]	**272**	508	**362**	688	1,777
	1,330	1,280	**5,573**	5,259	4,305
Distributions to noncontrolling interests	**(182)**	(179)	**(720)**	(680)	(535)
Distributions to redeemable noncontrolling	**(54)**	(34)	**(202)**	(114)	(79)
Preference share dividends	**(76)**	(74)	**(293)**	(288)	(245)
Maintenance capital expenditures[2]	**(205)**	(200)	**(671)**	(720)	(970)
Significant adjusting items:					
Weather normalization	**7**	16	**13**	(11)	(36)
Project development and transaction costs	**44**	2	**74**	44	19
Realized inventory revaluation allowance[3]	**1**	(52)	**(345)**	(474)	-
Employee severance and restructuring costs	**43**	30	**73**	30	6
Other items	**(29)**	87	**211**	108	41
Available cash flow from operations (ACFFO)	**879**	876	**3,713**	3,154	2,506

1 Changes in operating assets and liabilities include changes in 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 generation of a dependable and growing income stream.

STRATEGY

The Company's initiatives centre around eight areas of strategic emphasis in four key focus areas. 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* *Enhance strategic growth platforms*

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, a bolstering of 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 a significant 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, 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. Ongoing work to ensure Enbridge's project execution costs remain competitive in any market environment is a priority.

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. Sponsored vehicles also remain a critical component to ensuring efficient and low-cost access to financial markets. For further discussion on the Company's financing strategies, refer to *Liquidity and Capital Resources.*

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 helps enable cost effective capital raising by supporting one of the key tenets of the Company's investor value proposition, a reliable business model. For further details, refer to *Risk Management and Financial Instruments.*

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

A key strategic priority is the development and enhancement of strategic growth platforms from which to secure the Company's long-term future. As discussed under *Merger Agreement with Spectra Energy*, on September 6, 2016, Enbridge announced a definitive merger agreement with Spectra Energy. The combined company is expected to benefit from a diversified set of strategic growth platforms, including liquids and gas pipelines, United States and Canadian midstream businesses, an attractive portfolio of regulated natural gas distribution utilities and a growing renewable power generation business. The strength of the combined assets and geographic footprint will generate highly transparent and predictable cash flows underpinned by hiqh-quality commercial constructs that align closely with Enbridge's investor value proposition and significant on-going organic growth potential.

Strengthen Core Businesses

Within the Company's pre-merger 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 2016, despite unfavourable commodity market conditions, Enbridge's Mainline delivered record volumes of crude into United States markets. The Company's existing footprint, access to major North American markets, and the ability to incrementally enhance its capacity through low-cost expansions provide Enbridge's customers with an attractive and reliable path to market.

While executing its record growth capital program in recent years, the Company has also been undertaking an extensive integrity program across its liquids and gas systems. The Line 3 Replacement Program (L3R Program) being undertaken by Enbridge and EEP will support the safety and operational reliability of the mainline system, enhance flexibility, allow Enbridge and EEP to optimize throughput on the mainline system and restore approximately 370,000 bpd of capacity from western Canada into Superior, Wisconsin. For further details on the L3R Program, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Line 3 Replacement Program.*

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 $3.7 billion of regional infrastructure growth projects currently under development, including Enbridge's 70% share of the Norlite project, which is expected to enter service in 2017. In the Bakken region, Enbridge and EEP's growth is focused on the completion of the US$1.5 billion investment in the Bakken Pipeline System, in partnership with Energy Transfer. The Bakken Pipeline System will provide North Dakota producers enhanced access to premium light crude oil markets in both the eastern and western United States Gulf Coast. For recent developments on this matter, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Bakken Pipeline System (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 current and future natural gas and power businesses. The acquisition of Spectra Energy will provide Enbridge with a leading North American gas infrastructure franchise. Enbridge plans to expand and extend the Spectra Energy gas pipelines to serve growing demand markets in the United States, Canada and Mexico. Natural gas demand is anticipated to grow steadily through the next decade and Spectra Energy's assets are well positioned for continued profitable expansion.

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 in an environment of depressed prices, the Montney play continues to attract significant drilling activity. In 2016, the Company acquired two operating natural gas plants (the Tupper plants) and associated pipelines in northeastern British Columbia. The Company also continues to pursue ultra-deep water offshore natural gas and crude oil transmission opportunities. In 2016, the Company placed the Heidelberg Pipeline into service and the Stampede Oil Pipeline (Stampede Pipeline) is expected to be operational by 2018. Spectra Energy's western Canadian franchise adds a very significant scale to Enbridge's existing Canadian midstream business and it will position Enbridge as the leading gas processing company in the WCSB, with multiple infrastructure expansion and new construction opportunities.

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. Spectra Energy's Union Gas also operates within a highly attractive franchise area that offers considerable rate-base growth opportunities.

Enhance Strategic Growth Platforms

The development of new platforms to diversify and sustain long-term growth is an important strategic priority. The Merger Transaction goes a long way to achieving Enbridge's diversification objectives. It will position the Company with approximately 50% non-liquids infrastructure assets. It will also significantly increase Enbridge's footprint in growing United States markets such as Florida and the Northeast.

The Company will continue focusing on enhancing these new platforms and also on its development and diversification efforts to secure investment in additional renewable energy generation and Liquefied natural gas (LNG) development. Currently, Enbridge is expanding its renewable power efforts offshore of Europe under low-risk commercial structures with highly credit-worthy counterparties. In February 2017, the Company announced it had acquired an effective 50% interest in the partnership that holds the 497-MW Hohe See Offshore Wind Project in Germany, with a targeted in-service date in 2019. In 2016, Enbridge expanded its interests and development expertise in renewable power generation with the acquisitions of a 50% interest in a French offshore wind development company. Along with EDF, Enbridge will co-develop three large scale offshore wind farms off the coast of France that would produce a combined 1,428 MW of power. While development of these projects is still subject to final investment decision and regulatory approvals, the investment significantly extends the Company's offshore wind generation business which began with the acquisition of a 24.9% interest in the 400-MW Rampion Offshore Wind Project (Rampion Project) in the United Kingdom in 2015. The Rampion Project is anticipated to enter into service in 2018.

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 grow margins generated 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 continually earn public acceptance, 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. Enbridge also focuses on enhancing the effectiveness of 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 strives to build 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 programs and initiatives to ensure the perspective of its stakeholders help guide business decision making on sustainable development issues. With this in mind, in 2016 the Company launched the development of a new generation of environmental goals that reflect the shifting energy landscape in North America, including changing business needs and growing public interest in Enbridge's role in climate and energy issues. As part of this process, the Company updated its corporate Climate Policy in 2016, to more rigorously outline the steps Enbridge is taking to address climate change, including reducing its own carbon footprint and undertaking activities and engagement with external stakeholders on water protection.

The next generation of Enbridge's environmental goals will succeed the Company's Neutral Footprint Program, originally adopted in 2009, through which Enbridge committed to help reduce the environmental impact of its liquids pipeline expansion projects within five years of their occurrence by meeting certain goals for replacing trees, conserving land and generating kilowatt hours of green energy.

Enbridge provides annual progress updates related to the above initiatives in the Company's annual CSR Reports which can be found at http://csr.enbridge.com. ***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.***

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. In 2016, Enbridge launched its Building Our Energy Future program, which is aimed to improve and enhance the Company's competitiveness in the industry so it can continue to serve its stakeholders well and further strengthen its foundation for the future. As one of the initiatives under this program, the Company redesigned its organizational structure around new operating models for service delivery. As a consequence, in October 2016 the Company reduced its workforce by approximately 5%.

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 performance incentives to its employees.

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 Low Commodity Prices*, the downturn in price has impacted Enbridge's liquids pipelines' customers, who have responded by reducing their exploration and development spending for 2016 and into 2017. 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. Benchmark prices for WTI crude fell below US$30 per barrel at the beginning of 2016 and have remained volatile as the market seeks to re-balance supply and demand. Prices began to recover throughout the year, in response to anticipated cuts in OPEC country production among other factors, and have climbed above US$50 per barrel for short periods of time. WTI crude prices averaged US$43 per barrel for 2016 and ended the year above US$53 per barrel, with WTI crude prices averaging US$52.50 per barrel in January 2017.

Notwithstanding the low price environment, the Enbridge mainline system has thus far continued to be highly utilized and in fact, mainline throughput as measured at the Canada/United States border at Gretna, Manitoba saw record throughput of 2.6 million bpd in the month of December 2016. The mainline system continues to be subject to apportionment of heavy crudes, as nominated volumes currently exceed capacity on portions of the system. The impact of low crude oil prices on 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 Company's mainline system 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 and eastern Canada at a competitive cost relative to other alternatives. The fundamentals of oil sands production and low crude oil prices have 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 India and China. While OECD countries, including Canada, the United States and western European nations, will experience population growth, the 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, Brazil and OPEC. Growth in North America is largely driven by production from the oil sands and the continued development of tight oil plays including the Permian, Bakken and Eagle Ford 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 2016 and early 2017, North American supply growth can be influenced by macro-economic factors that drive down the global crude prices. OPEC has since changed its strategy after its November 2016 meeting in which OPEC agreed to cut production by 1.2 million bpd effective January 2017. 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.

In recent years, the combination of relatively flat domestic demand, growing supply and long-lead time to build pipeline infrastructure led to a fundamental change in the North American crude oil landscape. The inability to move increasing inland supply to tide-water markets resulted in a divergence between 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 completed by the industry in recent years, including those introduced by Enbridge, the crude oil price differentials significantly narrowed in 2015, and resulted in higher netbacks for producers. The differentials between WTI and world pricing remained narrow in 2016. This has resulted in crude oil continuing to move off of alternative transportation networks such as rail to fill the additional pipeline capacity as it became available. However, Canadian pipeline export capacity is expected to remain essentially full, resulting in incremental production utilizing non-pipeline transportation services until such time as pipeline capacity is made available. 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 2016, Enbridge continued to execute its growth projects plan in furtherance of this objective.

SUPPLY AND DEMAND FOR NATURAL GAS AND NGL

Global energy demand is expected to increase 30% by 2040, according to the International Energy Agency, driven primarily by economic growth in non-OECD countries. Natural gas will play an important role in meeting this energy demand as gas consumption is anticipated to grow by 50% during this period as one of the world's fastest growing energy sources, second only to renewables. Most natural gas demand will stem from the need for greater power generation capacity, as natural gas is a cleaner alternative to coal, which currently has the largest market share for power generation. Within North America, United States natural gas demand growth is expected to be driven by the next wave of gas-intensive petrochemical facilities which are now starting to enter service, along with power generation, an increase in the volume of LNG exports and additional pipeline exports 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. Canadian gas demand growth will be accelerated with implementation of proposed government regulations to replace coal fired power, designed to meet emissions targets.

North American supply from tight formations continues to create 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, and the rapidly growing Utica shale. The abundance of supply from these shale plays continues to fundamentally alter natural gas flow patterns in North America, as this region has largely displaced flows from the Gulf Coast and WCSB that historically supplied to eastern markets. Similar pressures are also being felt in the Midwest and southern markets. Additional production is expected from this region as pipeline constraints are eliminated, with several proposed pipeline projects targeted for in-service over the next two years.

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. The extended low commodity price environment in the basins in which the US Midstream business operates has resulted in reduced drilling activity and low volumes on the US Midstream business's systems. One exception is 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. Producers remain focused on the Montney shale and the developing Duvernay, where core areas are among the most competitive within North America. Economic drivers vary, but include: continuous productivity improvements, extremely low cost dry gas plays and abundant liquids and/or condensate rich gas resources, where liquid products enhance or drive economics. The highly prolific Permian Basin in West Texas/Southeast New Mexico is also experiencing significant benefit from technology improvements, where producer focus is primarily crude oil, however, with significant production of NGL-rich associated gas. In the longer term, while low natural gas prices are expected to be a key driver in future natural gas demand and infrastructure growth, producer break-even costs continue to decline and as a result it is expected there will continue to be ample economic supply that will respond quickly to rising demand, thereby limiting price advances.

Natural gas prices have been relatively weak over the last year as a result of warm weather and high storage inventories; however, although rig counts have trended lower, production levels have remained generally flat due to productivity gains, the high number of drilled and uncompleted wells and continued focus on liquids-rich and condensate plays. 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. The robust gas production has created regional supply imbalances for some NGL products and weakened the economics of NGL extraction, although these imbalances modestly improved over the second half of 2016 as crude prices have rebounded and NGL export capacity has expanded.

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 that has started to enter service and will accelerate in 2017. When this new infrastructure is completed and fully online in late 2018, ethane prices and resulting extraction margins are expected to improve, reducing the amount of ethane retained in the gas stream. In addition, the inaugural export cargo of ethane was shipped in March 2016 and if waterborne exports rise significantly, the ethane market will further 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, with volumes reaching over one million bpd at times in 2016, which have helped to reduce the inventory overhang and provide support to propane prices.

In Canada, the WCSB is well-situated to capitalize on the evolving NGL fundamentals over the longer term as the Montney and Duvernay shale plays contain significant liquids-rich resources at competitive extraction costs. Longer-term, NGL fundamentals indicate a positive outlook for demand growth, and would be further supported with a continued recovery in crude oil prices. 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.

Conditions for western Canadian LNG exports remain favourable, as industry proponents continue to assess updated project economics considering a scale down in construction costs, ample low-cost gas supplies and a stabilizing market, as supply/demand forecasts show signs of rebalancing. Proponents who have the benefit of an integrated model (upstream supply and downstream market) have the greatest probability of making a favourable final investment decision. There continues to be regional opposition to proposed projects in general, primarily stemming from a climate change/greenhouse gas (GHG) emissions agenda, mixed with some local Indigenous opposition as it relates to environmental impacts on wildlife and fish habitats. The Government of British Columbia continues to advocate strongly for west coast LNG. The short term outlook for LNG fundamentals points to a continued oversupply, as it will take some time for the market to fully absorb the large volumes of new supply coming online. Post-2025, forecasts indicate demand will exceed projected supply as growing markets seek to diversify supply sources. This should be supportive of Canadian LNG exports.

In response to these evolving natural gas and NGL fundamentals, Enbridge believes it is well-positioned to provide value-added solutions to producers. Enbridge is responding to the need for regional infrastructure with additional investment in Canadian and United States midstream processing and pipeline facilities. Alliance Pipeline traverses through the heart of key liquids-rich plays in the WCSB and Bakken, 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 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, which provides producers with access to premium NGL markets. Vector is also well positioned to deliver increasing Marcellus and Utica production to eastern markets.

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 Canada 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 82 gigawatts (GW) of installed wind power capacity and in Canada over 11 GW of installed wind power 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 35 GW of installed solar photovoltaic capacity. 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 (PPAs) 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. According to the European Wind Energy Association, by 2030, wind energy capacity in Europe is expected to be 320 GW, including 66 GW of offshore capacity. There is also wide public support for carbon reduction targets and broader adoption of renewable generation across all governmental levels. Furthermore, governments in Europe are seeking 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 February 2017, the Company announced it had acquired an effective 50% interest in the partnership that holds the 497-MW Hohe See Offshore Wind Project in Germany. Earlier in 2016, Enbridge announced the acquisition of the 249-MW Chapman Ranch Wind Project in Texas, as well as the acquisition of a 50% interest in a French offshore wind development company, Éolien Maritime France SAS (EMF). In late 2015, Enbridge announced acquisitions of the 103-MW New Creek Wind Project in West Virginia and a 24.9% interest in the 400-MW Rampion Project in the United Kingdom. The New Creek Wind Project was subsequently completed and placed into service in December 2016. Including these acquisitions, Enbridge has invested over $5 billion in renewable power generation and transmission since 2002. The Company will continue to seek new opportunities to expand its power generation business and growing its portfolio by investing in assets that meet its investment criteria.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

A key element of Enbridge's corporate strategy is the successful execution of its growth capital program. In 2016, Enbridge successfully placed into service over $2 billion of growth projects across several business units. With approximately $10 billion of growth projects placed into service over the last two years, Enbridge portfolio of approximately $27 billion of growth projects includes $17 billion of growth projects expected to be placed into service between 2017 and 2019.

In 2016, within the Liquids Pipelines segment, EEP completed and placed into service the expansion of Line 6B on the Lakehead System. This expansion, which is the final component of the Company's Eastern Access Program, provides increased access to refineries in the upper midwest United States and eastern Canada. EEP also continued to execute on the Lakehead System Mainline Expansion through completion of additional tankage on the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois.

In 2017, the Company expects to place into service approximately $5.6 billion of growth projects, inclusive of Enbridge's 70% share of the $1.3 billion Norlite project, as well as the Company's investment in the Bakken Pipeline System. In January 2017, the Company completed the Athabasca Pipeline Twin portion of the Regional Oil Sands Optimization Project, whereas the Wood Buffalo Extension component is now expected to be in service in December 2017. Beyond 2017, the Company will continue to execute its liquids pipelines market access strategy through the completion of the L3R Program.

Within the Gas Distribution segment, the completion of the GTA project in 2016 has enabled EGD to meet the growing demand for natural gas distribution services in the GTA while ensuring the ongoing safe and reliable delivery of natural gas to its current and future customers. The system expansion is the largest ever undertaken by EGD and it significantly bolsters EGD's rate base and expected earnings going forward.

In 2016, Enbridge also expanded its natural gas pipelines and processing businesses with the acquisition of the Tupper Plants and associated pipelines in the Montney region of northeastern British Columbia from a Canadian subsidiary of Murphy Oil Corporation. Together, the two plants have capacity of 320 million cubic feet per day and will serve to enhance the Company's natural gas footprint within the Montney region, one of the most attractive natural gas plays in North America. Other projects completed within the Gas Pipelines and Processing segment included the 100,000 bpd Heidelberg Pipeline in the Gulf of Mexico and the expansion of the Aux Sable Extraction Plant in Channahon, Illinois, providing approximately 24,500 bpd of incremental fractionation capacity to this plant.

In keeping with the Company's strategic priority to enhance strategic growth platforms and sustain long-term growth, Enbridge continues to expand its renewable energy generation capacity. Within the Green Power and Transmission segment, the New Creek Wind Project entered service in December 2016, increasing Enbridge's net operating renewable power generating capacity to approximately 1,900-MW. Also in 2016, Enbridge announced the acquisition of the 249-MW Chapman Ranch Wind Project in Texas. Construction on the Company's previously announced 24.9% interest in the 400-MW Rampion Project in the United Kingdom is also continuing, with these two projects expected to be placed into service in 2017 and 2018, respectively. In February 2017, the Company also announced it had acquired an effective 50% interest in the partnership that holds the 497-MW Hohe See Offshore Wind Project in

Germany, with a targeted in-service date in 2019, increasing Enbridge's net operating renewable power generating capacity to approximately 2,500 MW.

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, 2016.

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
LIQUIDS PIPELINES				
1. Eastern Access (EEP)[3]	US$0.3 billion	US$0.3 billion	2016	Complete
2. Norlite Pipeline System (the Fund Group)[4]	$1.3 billion	$0.8 billion	2017	Under construction
3. JACOS Hangingstone Project (the Fund Group)	$0.2 billion	$0.1 billion	2017	Under construction
4. Regional Oil Sands Optimization Project (the Fund Group)	$2.6 billion	$2.2 billion	2017 (in phases)	Under construction
5. Bakken Pipeline System (EEP)	US$1.5 billion	No significant expenditures to date	2017	Under construction
6. Lakehead System Mainline Expansion (EEP)[3]	US$0.8 billion	US$0.7 billion	2016-2019 (in phases)	Under construction
7. Canadian Line 3 Replacement Program (the Fund Group)[5]	$4.9 billion	$1.5 billion	2019	Pre-construction
8. U.S. Line 3 Replacement Program (EEP)[3,5]	US$2.6 billion	US$0.4 billion	2019	Pre-construction
9. Sandpiper Project (EEP)[6]	US$2.6 billion	US$0.8 billion	Application withdrawn	Application withdrawn
GAS DISTRIBUTION				
10. Greater Toronto Area Project	$0.9 billion	$0.9 billion	2016	Complete
GAS PIPELINES AND PROCESSING				
11. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-TBD (in phases)	Complete
12. Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	TBD	Complete
13. Eaglebine Gathering (EEP)	US$0.2 billion	US$0.1 billion	2015-TBD (in phases)	Complete (Phase 1)
14. Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Complete
15. Tupper Main and Tupper West Gas Plants	$0.5 billion	$0.5 billion	2016	Acquisition completed
16. Aux Sable Extraction Plant Expansion	US$0.1 billion	US$0.1 billion	2016	Complete
17. Stampede Oil Pipeline	US$0.2 billion	US$0.1 billion	2018	Under construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)				
GREEN POWER AND TRANSMISSION				
18. New Creek Wind Project	US$0.2 billion	US$0.2 billion	2016	Complete
19. Chapman Ranch Wind Project	US$0.4 billion	US$0.3 billion	2017	Under construction
20. Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.4 billion (£0.20 billion)	2018	Under construction
21. Hohe See Offshore Wind Project[7]	$1.7 billion (€1.07 billion)	No significant expenditures to date	2019	Pre-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, 2016.

3 The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP. As discussed under L3R Program below, following EEP's January 27, 2017 announcement, the U.S. L3R Program is being funded 99% by Enbridge and 1% by EEP. EEP also increased its joint funding in Eastern Access by 15%.

4 Enbridge will construct and operate Norlite. Keyera Corp. will fund 30% of the project.

5 As discussed under L3R Program below, the expected cost and in-service date of this project is under review by the Company in light of the schedule for regulatory review and approval communicated by the MNPUC on October 28, 2016.

6 The Company planned to construct and operate the Sandpiper Project with MPC funding 37.5% of the project. However, on October 28, 2016, the MNPUC approved EEP's application to withdraw the Sandpiper Projects regulatory applications without conditions.

7 In February 2017, Enbridge acquired an effective 50% interest in the Hohe See Offshore Wind Project.

Risks related to the development and completion of growth projects are described under *Risk Management and Financial Instruments – General Business Risks.*

Liquids Pipelines

1 Eastern Access (EEP)

2 Norlite Pipeline System (the Fund Group)

3 JACOS Hangingstone Project (the Fund Group)

4 Regional Oil Sands Optimization Project (the Fund Group)

5 Bakken Pipeline System (EEP)

6 Lakehead System Mainline Expansion (EEP)

7 Canadian Line 3 Replacement Program (the Fund Group)

8 U.S. Line 3 Replacement Program (EEP)

9 Sandpiper Project (EEP)

LIQUIDS PIPELINES

Eastern Access (EEP)

The Eastern Access initiative included a series of Enbridge and EEP crude oil pipeline projects to provide increased access to refineries in the upper midwest United States and eastern Canada. The majority of the Canadian and United States components of the Eastern Access initiative were completed between 2013 and 2015. The remaining component of the Eastern Access initiative involved a further upsizing of EEP's Line 6B. The Line 6B capacity expansion from Griffith, Indiana to Stockbridge, Michigan increased capacity from 500,000 bpd to 570,000 bpd and included pump station modifications at the Griffith, Niles and Mendon stations, additional modifications at the Griffith and Stockbridge terminals and breakout tankage at Stockbridge. This expansion was placed into service in June 2016 at a total cost of approximately US$0.3 billion.

The Eastern Access projects undertaken by EEP were funded 75% by Enbridge and 25% by EEP. On January 27, 2017, EEP exercised its option to acquire an additional 15% economic interest in the Eastern Access projects at a book value of approximately US$360 million.

In July 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, until the second quarter of 2016, Enbridge's capital funding contribution requirements to the Eastern Access projects were offset against its foregone cash distribution.

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 and based on current engineering design, will provide an initial capacity of approximately 218,000 bpd of diluent, with the potential to be further expanded to approximately 465,000 bpd of capacity with the addition of pump stations. Norlite will be anchored by throughput commitments from Suncor Energy Inc., Total E&P Canada Ltd. and Teck Resources Limited (Fort Hills Partners) for production from the proposed Fort Hills Partners' oil sands project (Fort Hills Project) and from Suncor Energy Oil Sands Limited Partnership's (Suncor Partnership) 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 the second quarter of 2017 at an estimated cost of approximately $1.3 billion, with expenditures to date of approximately $0.8 billion.

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, has been delayed at the shippers' request and is targeted to enter service in the third quarter of 2017. 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)

As part of the Regional Oil Sands Optimization project, in January 2017 the Company completed the twinning of the southern section of the Athabasca Pipeline with a 36-inch diameter pipeline from Kirby Lake, Alberta to the crude oil hub at Hardisty, Alberta. The initial capacity of the Athabasca Pipeline Twin is 450,000 bpd and it can be further expanded in the future to 800,000 bpd through additional pumping horsepower.

The Regional Oil Sands Optimization project also 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 connect to the origin of the Athabasca Pipeline Twin at Kirby Lake, Alberta. This component of the project is now expected to be in service in December 2017 to align with the primary shipper's production profile.

The estimated total cost of the Regional Oil Sands Optimization Project is approximately $2.6 billion, with expenditures to date of approximately $2.2 billion.

The integrated Wood Buffalo Extension and Athabasca Pipeline Twin will transport diluted bitumen from the proposed Fort Hills Project in northeastern Alberta, as well as from oil sands production from the Suncor Partnership in the Athabasca region. The Athabasca Pipeline Twin portion of the project, after being placed into service in January 2017, is also shipping blended bitumen from the Cenovus Christina Lake Steam Assisted Gravity Drainage project near the origin of the Athabasca Pipeline Twin.

Bakken Pipeline System (EEP)
In August 2016, Enbridge and EEP announced that EEP had entered into an agreement with MPC to form a new joint venture, MarEn Bakken Company LLC, which in turn has entered into an agreement to acquire a 49% equity interest in the holding company that owns 75% of the Bakken Pipeline System from an affiliate of Energy Transfer Partners, L.P. and Sunoco Logistics Partners, L.P. Under this arrangement, EEP and MPC would indirectly hold 75% and 25% interests, respectively, of the joint venture's 49% interest in the holding company of the Bakken Pipeline System. This transaction was closed on February 15, 2017. The purchase price of EEP's effective 27.6% interest in the Bakken Pipeline System is US$1.5 billion.

EEP will fund the US$1.5 billion acquisition through a bridge loan provided by Enbridge through one of its affiliates. The bridge loan will remain in place until a joint funding arrangement with Enbridge and its affiliates is finalized. A special committee of independent directors of the board of Enbridge Management has been established that would establish a joint funding arrangement for this investment. This arrangement, which is expected to be finalized in the second quarter of 2017, remains subject to the review of the conflicts committee of the Board of EEP's General Partner (GP).

The Bakken Pipeline System connects the prolific Bakken formation in North Dakota to markets in eastern PADD II and the United States Gulf Coast, providing customers with access to premium markets at a competitive cost. The Bakken Pipeline System consists of the Dakota Access Pipeline and the Energy Transfer Crude Oil Pipeline projects. The Dakota Access Pipeline consists of 1,886 kilometres (1,172 miles) of 30-inch pipeline from the Bakken/Three Forks production area in North Dakota to Patoka, Illinois. It is expected to initially deliver in excess of 470,000 bpd of crude oil and has the potential to be expanded to 570,000 bpd. The Energy Transfer Crude Oil Pipeline consists of 100 kilometres (62 miles) of new 30-inch diameter pipe, 1,104 kilometres (686 miles) of converted 30-inch diameter pipe, and 64 kilometres (40 miles) of converted 24-inch diameter pipe from Patoka, Illinois to Nederland, Texas.

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, and 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 pipeline (Line 78). The expansion of Line 67 and construction of Line 78 were completed in 2015.

The Line 67 pipeline capacity expansion remains subject to the receipt of an amendment to the current Presidential Permit to allow for operation of the Line 67 pipeline at the United States/Canada border at its currently planned operating capacity of 800,000 bpd. On February 10, 2017, the United States Department of State (Department), the agency that is responsible for issuing permits for cross-border pipelines pursuant to a delegation of authority by the President under an Executive Order, issued a Draft Supplemental Environmental Impact Statement (Draft SEIS), which determined that there were no significant adverse environmental impacts from the planned capacity increase. Upon closure of a public comment period on the Draft SEIS, which is currently scheduled for March 27, 2017, the Department will review all received comments and prepare a Final SEIS. The Executive Order also requires that the Department initiate a 90-day inter-agency consultation period to solicit comments from certain other federal agencies on whether the Line 67 expansion will serve the “national interest.” Following issuance of the Final SEIS and completion of the inter-agency consultation process, the Administration will make a decision and issue a Presidential Permit if it finds that doing so is in the national interest. This is expected later in the year and meanwhile, 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 remaining scope of the Lakehead System Mainline Expansion includes the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois. Included therein was additional tankage of approximately US$0.4 billion which was completed on various dates between the third quarter of 2015 and the third quarter of 2016. In addition, the expansion to increase the pipeline capacity to 1,200,000 bpd requires only the addition of pumping horsepower with no pipeline construction and is expected to cost approximately US$0.4 billion. In conjunction with shippers, a decision was made to delay the in-service date of this phase of the Southern Access expansion to 2019 to align more closely with the anticipated in-service date for the U.S. L3R Program. The expenditures incurred to date are approximately US$0.7 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. In July 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, until the second quarter of 2016, Enbridge’s capital funding contribution requirements to the Lakehead System Mainline Expansion were offset against its foregone cash distribution.

Line 3 Replacement Program

In 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. The L3R Program will support the safety and operational reliability of the mainline system, enhance flexibility, allow the Company and EEP to optimize throughput on the mainline system and restore approximately 370,000 bpd of capacity from western Canada into Superior, Wisconsin.

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.

In April 2016, the NEB found that the Canadian L3R Program is in the Canadian public interest and issued final conditions and a recommendation to the Federal Cabinet to issue the Certificate of Public Convenience and Necessity (the Certificate) for the construction and operation of the pipeline and related facilities. A decision by the Federal Cabinet was expected to be issued three months following the NEB recommendation per legislation. However, because of the Federal Government’s January 27, 2016 announcement that, outside of the NEB process it had directed Federal agencies to conduct an assessment of direct and upstream GHG emissions and incremental consultation with affected communities and Indigenous peoples, the Minister of Natural Resources sought an extension of four months to the Government’s legislated decision-making time limit (to seven months in total). Regulatory approval was received from the Government of Canada on November 29, 2016 with no material changes to permit conditions and on December 1, 2016, the NEB issued the Certificate. Once the Certificate was issued, Natural Resources Canada released the final assessment of the upstream GHG emissions, as well as reports summarizing the additional Crown Consultation with Indigenous groups and the public online survey conducted by Natural Resources Canada.

The report assessing the upstream GHG emissions estimates that the upstream GHG emissions in Canada associated with the production and processing of crude oil transported by the Canadian L3R Program, based on a capacity of 760,000 bpd, could be between 19 and 26 megatonnes of carbon dioxide equivalent per year. The report also found that the estimated emissions are not necessarily incremental; the degree to which the estimated emissions would be incremental depends on the expected price of oil, the availability and costs of other transportation modes, such as crude by rail, and whether other pipeline projects are built. The Crown Consultation report concluded that the NEB recommended conditions along with the commitments made by Enbridge are responsive to, and reasonably accommodate the project specific concerns raised by Indigenous groups and that other concerns will be addressed by the Government's commitment to modernize the NEB and to review the environmental assessment legislation. The report summarizing the online survey states that 3,170 submissions were received in response to the questionnaire including from both individuals directly affected by the project, as well as general members of the public, and the report concluded that the majority of concerns centered around issues dealt with by the NEB including soil and ground water contamination and impact to farmers and nearby communities.

In December 2016, the Manitoba Metis Federation and the Association of Manitoba Chiefs applied to the Federal Court of Appeal (Federal Court) for leave to judicially review the Government of Canada's decision to approve the Canadian L3R Program. The outcome or timing of these proceedings, including their potential impact upon the Canadian L3R Program cannot be predicted at this time.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in 2019 at an estimated capital cost of approximately $4.9 billion, with expenditures to date of approximately $1.5 billion. With a delay in construction arising from a longer than anticipated permitting process, the cost of this project is expected to increase. Also, in view of the MNPUC's decision in respect of the schedule for the remainder of the regulatory approval process for the U.S. L3R Program, as discussed in *United States Line 3 Replacement Program (EEP)* below, the Company is reviewing the expected impact on the Canadian L3R Program's schedule and cost estimates. It is possible that the in-service date could be delayed, at least until later in 2019. 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)

The U.S. L3R Program 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.

EEP is in the process of obtaining the appropriate permits for constructing the U.S. L3R Program in Minnesota. The project requires both a Certificate of Need and an approval of the pipeline's route (Route Permit) from the MNPUC. The MNPUC found both the Certificate of Need and Route Permit applications for the U.S. L3R Program through Minnesota to be complete. With respect to the Route Permit, the Minnesota Department of Commerce (DOC) held public scoping meetings in August 2015.

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 DOC to prepare a final Environmental Impact Statement (EIS) 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. On February 5, 2016, EEP filed a Petition for Reconsideration of the requirement to provide a final EIS ahead of the commencement of the Certificate of Need and Route Permit proceedings noted in the U.S. L3R Order. At a hearing held on March 24, 2016, the MNPUC denied the Petition for Reconsideration.

With the issuance of the Environmental Assessment Worksheet (EAW) on April 11, 2016, the MNPUC commenced the EIS process. Consultation regarding the EAW, which defines the scope of the EIS, commenced with a series of public meetings in communities in Minnesota on April 25, 2016, which concluded on May 13, 2016. The DOC addressed the comments received on the draft EIS scope and issued its scoping recommendations to the MNPUC on September 22, 2016.

Three external parties filed motions requesting that the scoping process be re-opened or that a comment period be established because of the issuance of the Consent Decree settling the Line 6B pipeline crude oil release in Marshall, Michigan and the withdrawal of regulatory applications pending with the MNPUC with respect to the Sandpiper Project discussed below. EEP filed a reply challenging the need to re-open the scoping process indicating that neither of these events warrants further extension of time. The motions filed by the external parties were considered and denied by the MNPUC at a hearing held on October 28, 2016.

At the hearing on October 28, 2016, the MNPUC also approved the scope of the EIS. The MNPUC’s decision was confirmed in a written order on November 30, 2016. The DOC published the EIS Public Notice on December 5, 2016, which provided greater clarity with respect to the timeline for the regulatory approval of the U.S. L3R Program in Minnesota. On December 20, 2016, two intervenors filed petitions for reconsideration of the MNPUC's November 30, 2016 order. EEP filed a response on January 3, 2017. The MNPUC denied the petitions at a hearing which took place on February 9, 2017. EEP is currently evaluating the impact of the MNPUC’s November 30, 2016 order on the cost and in-service date of this project. It is possible, under the schedule approved by the MNPUC, that the in-service date could be delayed, at least until later in 2019.

On January 27, 2017, Enbridge and EEP entered into an agreement for the joint funding of the U.S. L3R Program, whereby Enbridge and EEP will fund 99% and 1%, respectively, of the project cost. Enbridge has reimbursed EEP approximately US$450 million for expenditures incurred to date on the project and it will fund 99% of the capital costs through construction. EEP has the option to increase its economic interest by up to 40% at book value until four years after the project is placed into service.

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)
The Sandpiper Project was part of the Light Oil Market Access Program initiative and would have expanded and extended EEP's North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System would have been expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion involved 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 would have twinned 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.

On September 1, 2016, EEP announced that it applied for the withdrawal of regulatory applications for the Sandpiper Project pending with the MNPUC because EEP concluded that the project should be delayed until such time as crude oil production in North Dakota recovers sufficiently to support development of new pipeline capacity. Based on updated projections, EEP expects that this pipeline capacity will not likely be needed until beyond its current five-year planning horizon. On October 28, 2016, the MNPUC approved EEP’s application to withdraw the regulatory applications without conditions and issued the written order on November 10, 2016.

In connection with the above announcement and other factors, EEP also evaluated the Sandpiper Project for impairment and determined that the project was impaired. In the third quarter of 2016, EEP recorded an asset impairment of US$763 million, including related project costs. Of the total amount, US$270 million was allocated to MPC, EEP’s partner in the Sandpiper Project, and US$493 million was attributable to EEP’s unitholders. The Company’s Consolidated Statements of Earnings for the year ended December 31, 2016 includes a gross charge, including additional project costs incurred in the fourth quarter, of $1,004 million, of which $875 million was attributable to noncontrolling interests in EEP and MPC and $81 million after-tax attributable to Enbridge’s common shareholders.

GAS DISTRIBUTION

Greater Toronto Area (GTA) Project

EGD undertook 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 involved 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) as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in the GTA. Both the Western and Eastern segments were placed into service in March 2016. The total project cost was approximately $0.9 billion.

Gas Distribution

10 Greater Toronto Area Project

GAS PIPELINES AND PROCESSING

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and several other producers, to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, the Company constructed and owns and operates 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 assess the extent of the delay. Notwithstanding the Big Foot platform installation delay, the Company began collecting certain fees specified in the transportation services agreements effective 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 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

- **11** Walker Ridge Gas Gathering System
- **12** Big Foot Oil Pipeline
- **13** Eaglebine Gathering (EEP)
- **14** Heidelberg Oil Pipeline
- **15** Tupper Main and Tupper West Gas Plants
- **16** Aux Sable Extraction Plant Expansion
- **17** Stampede Oil Pipeline

Assets in Operation
Growth Projects
Gas Plants in Operation

Eaglebine Gathering (EEP)
In 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. One of the transactions involved MEP acquiring New Gulf Resources, LLC's midstream business in Leon, Madison and Grimes Counties, Texas. The acquisition was completed in 2015 and consisted of a natural gas gathering system that is currently in operation. In 2015, EEP and MEP also completed construction of the Ghost Chili pipeline project, which consisted of a lateral and associated facilities that created 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. As part of Phase I, 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. 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 April 2016, Enbridge completed the acquisition of the Tupper Plants and associated pipelines from a Canadian subsidiary of Murphy Oil Corporation for a purchase price of approximately $0.5 billion. The Tupper Plants have a combined total licensed capacity of 320 million cubic feet per day and are located within the Montney gas play, 35 kilometres (22 miles) 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 (33 miles) of high pressure pipelines, are currently in operation and are underpinned by long-term take-or-pay contracts.

Aux Sable Extraction Plant Expansion
In September 2016, the Company completed the expansion of fractionation capacity and related facilities at the Aux Sable extraction and fractionation plant located in Channahon, Illinois. The expansion provides approximately 24,500 bpd of incremental fractionation capacity and 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 Company's share of the project cost was approximately US$0.1 billion.

Stampede Oil Pipeline
In 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. Expenditures incurred to date are approximately US$0.1 billion.

Green Power and Transmission

18 New Creek Wind Project

19 Chapman Ranch Wind Project

20 Rampion Offshore Wind Project

21 Hohe See Offshore Wind Project

Power Transmission in Operation
Wind Assets in Operation
Solar Assets in Operation
Growth Projects – Wind

GREEN POWER AND TRANSMISSION

New Creek Wind Project

In 2015, Enbridge announced it had acquired a 100% interest in the 103-MW New Creek Wind Project, located in Grant County, West Virginia, from EverPower Wind Holdings, LLC. The project comprised 49 Gamesa turbines and it entered service in December 2016. The New Creek Wind Project was constructed under a fixed-price engineering, procurement and construction agreement, with White Construction Inc. at a total cost of approximately US$0.2 billion. Gamesa is providing turbine operations and maintenance services under a five-year fixed price contract. The project was backed by medium and long-term power offtake agreements, as well as renewable energy credit sales.

Chapman Ranch Wind Project

On September 9, 2016, Enbridge acquired a 100% interest in the 249-MW Chapman Ranch Wind Project, located in Nueces County, Texas, from Apex Clean Energy Holdings, LLC. Enbridge's total investment is expected to be approximately US$0.4 billion, with expenditures incurred to date of approximately US$0.3 billion. The Chapman Ranch Wind Project will consist of 81 Acciona Windpower North America, LLC (Acciona) turbines and is expected to be in service in the third quarter of 2017. The project is being constructed under a fixed-price engineering, procurement and construction agreement, with Renewable Energy Systems America Inc. Acciona will provide turbine operations and maintenance services under a five-year fixed-price contract with an option to extend. The project is backed by a 12-year power offtake agreement.

Rampion Offshore Wind Project

In 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. 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 SE retaining the balance of 50.1% interest. Enbridge has incurred costs to date of approximately $0.4 billion (£0.20 billion).

Hohe See Offshore Wind Project

On February 17, 2017, the Company announced it had acquired an effective 50% interest in the partnership that will construct the 497-MW Hohe See Offshore Wind Project. Enbridge will partner with state-owned German utility EnBW in the construction and operation of this late-design project, with the target in-service date of 2019. The Hohe See Offshore Wind Project is located in the North Sea, 98 kilometres (61 miles) off the coast of Germany and will be constructed under fixed-price engineering, procurement, construction and installation contracts, which have been secured with key suppliers. The Hohe See Offshore Wind Project is backed by a government legislated 20-year revenue support mechanism. Enbridge's total investment in this project through the project's completion and in-service date in 2019 is expected to be approximately $1.7 billion (€1.07 billion), including planned spend of approximately $0.6 billion (€0.44 billion) throughout 2017.

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

LIQUIDS PIPELINES

Northern Gateway Project

Northern Gateway involved 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 was 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 was 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 Joint Review Panel (JRP) which 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."

In June 2014, the Governor in Council (GIC) approved Northern Gateway, subject to 209 conditions. Nine applications to the Federal Court for leave for judicial review of the Order in Council approving the project 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 decision of the Federal Court was released on June 30, 2016. The Federal Court found that for the most part the environmental review and Aboriginal consultation processes were reasonable, and the legal challenges to those aspects of the process were dismissed. However, the Federal Court found the Phase IV Crown consultation process undertaken by the Federal Government was unacceptably flawed, and for that reason it quashed the Certificates and sent the matter back to the GIC for redetermination.

The Federal Court indicated that the GIC had three options available on redetermination: it could redo the Phase IV Crown consultation and then direct the NEB to issue the Certificates, it could direct the NEB to dismiss the application for the Certificates, or it could ask the NEB to reconsider its recommendations.

Neither Northern Gateway nor the Federal Government sought leave to appeal to the Supreme Court of Canada.

The Federal Government chose not to re-do the Crown consultation. By way of an Order in Council dated November 25, 2016, the GIC directed the NEB to dismiss Northern Gateway's application for the Certificates. On December 6, 2016, the NEB issued orders rescinding the Certificates, thereby effectively cancelling the project.

In consultation with the potential shippers and Aboriginal equity partners, the Company has assessed the Federal Government's decision and concluded that Northern Gateway cannot proceed as envisioned. Project activity is limited to winding down while evaluating potential value preservation options. Total expenditures incurred to date on the project are approximately $656 million. After taking into consideration the amount recoverable from potential shippers on Northern Gateway, the Company reflected an impairment of $373 million ($272 million after-tax) in the fourth quarter of 2016 within the Liquids Pipelines segment.

GREEN POWER AND TRANSMISSION

Éolien Maritime France SAS

Effective May 19, 2016, Enbridge acquired a 50% interest in EMF, a French offshore wind development company. EMF is co-owned by Enbridge and EDF Energies Nouvelles, a subsidiary of Électricité de France S.A. EMF holds licenses for three large-scale offshore wind farms off the coast of France that would produce a combined 1,428 MW of power. The development of these projects is subject to final investment decision and regulatory approvals, the timing of which is not yet certain. Enbridge's portion of the costs incurred to date is approximately $194 million (€136 million).

LIQUIDS PIPELINES

EARNINGS BEFORE INTEREST AND INCOME TAXES

	2016	2015	2014
(millions of Canadian dollars)			
Canadian Mainline	**931**	896	663
Lakehead System	**1,425**	1,108	836
Regional Oil Sands System	**384**	341	301
Mid-Continent and Gulf Coast	**656**	516	319
Southern Lights Pipeline	**168**	155	121
Bakken System	**198**	213	233
Feeder Pipelines and Other	**196**	155	119
Adjusted earnings before interest and income taxes	**3,958**	3,384	2,592
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**467**	(1,390)	(499)
Canadian Mainline - Line 9B costs incurred during reversal	**-**	(3)	(5)
Lakehead System - changes in unrealized derivative fair value gains/(loss)	**(6)**	(10)	8
Lakehead System - hydrostatic testing	**15**	(72)	-
Lakehead System - leak remediation costs, net of leak insurance recovery	**3**	-	(97)
Regional Oil Sands System - northeastern Alberta wildfires pipelines and facilities restart costs	**(47)**	-	-
Regional Oil Sands System - make-up rights adjustment	**(32)**	9	8
Regional Oil Sands System - leak remediation and long-term pipeline stabilization costs, net of leak insurance recoveries	**5**	26	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)	**(2)**	(7)	4
Mid-Continent and Gulf Coast - make-up rights adjustment	**(97)**	(54)	(41)
Southern Lights Pipeline - changes in unrealized derivative fair value gains/(loss)	**19**	(87)	3
Bakken System - Sandpiper asset impairment	**(1,004)**	-	-
Bakken System - asset impairment	**-**	(86)	-
Bakken System - changes in unrealized derivative fair value gains/(loss)	**(4)**	(5)	4
Bakken System - make-up rights adjustment	**2**	8	(3)
Feeder Pipelines and Other - gain on sale of South Prairie Region assets	**850**	-	-
Feeder Pipelines and Other - Northern Gateway asset impairment loss	**(373)**	-	-
Feeder Pipelines and Other - Eddystone Rail impairment loss	**(184)**	-	-
Feeder Pipelines and Other - gain on sale of non-core assets	**-**	91	-
Feeder Pipelines and Other - derecognition of regulatory balances	**(6)**	-	-
Feeder Pipelines and Other - make-up rights adjustment	**(2)**	(6)	5
Feeder Pipelines and Other - project development costs	**(5)**	(3)	(4)
Feeder Pipelines and Other - changes in unrealized derivative fair value loss	**-**	(1)	-
Earnings before interest and income taxes	**3,557**	1,806	1,980

Liquids Pipelines adjusted EBIT was $3,958 million in 2016 compared with adjusted EBIT of $3,384 million in 2015 and $2,592 million in 2014. The Company continued to realize growth on the Canadian Mainline, Lakehead System and Regional Oil Sands System primarily due to higher throughput that resulted from strong oil sands production in western Canada enabled by pipeline capacity expansion projects placed into service in 2015 and 2014. However, the positive effect of increased capacity on liquids pipelines throughput was substantially negated in the second quarter by the impact of extreme wildfires in northeastern Alberta which led to a temporary shutdown of certain of the Company's upstream pipelines and terminal facilities resulting in a disruption of service on Enbridge's Regional Oil Sands System with corresponding impacts on Enbridge's downstream pipelines deliveries, including Canadian Mainline and the Lakehead System. Growth in Canadian Mainline adjusted EBIT was also affected by a combination of a lower average IJT Residual Benchmark Toll, which decreased effective April 1, 2016, and a lower foreign exchange rate on hedges used to convert United States dollar denominated toll revenue on the Canadian Mainline in 2016. The Lakehead System delivered strong operating performance driven by higher Lakehead System Local Toll, higher throughput and contributions from new assets placed into service in 2015. In 2016, the Company also benefitted from stronger adjusted EBIT contributions from the United States Mid-Continent and Gulf Coast systems, attributable to increased transportation revenues mainly resulting from an increase in the level of committed take-or-pay volumes on Flanagan South.

Additional details on items impacting Liquids Pipelines EBIT include:

- Canadian Mainline EBIT for each year reflected changes in unrealized fair value gains and 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 EBIT for 2015 and 2014 included depreciation expense 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 2016 included recoveries, as well as charges in 2015, in relation to hydrostatic testing performed on Line 2B in 2015.
- Lakehead System EBIT for 2016 and 2014 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release, as well as insurance recoveries associated with the Line 6A crude oil release.
- Regional Oil Sands System EBIT for each year included make-up rights adjustments. 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 each year included insurance recoveries, as well as charges in 2015 and 2014, 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*.
- Southern Lights Pipeline EBIT for each year 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 loss before interest and income taxes for 2016 reflected impairment charges, including related project costs, on EEP's Sandpiper Project resulting from the withdrawal of the regulatory applications in September 2016 that were pending with the MNPUC. For additional information, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Sandpiper Project (EEP)*.
- 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 2016 reflected a gain on the sale of non-core South Prairie Region assets.
- Feeder Pipelines and Other EBIT for 2016 included an asset impairment charge related to Northern Gateway. For additional information, refer to *Other Announced Projects Under Development – Liquids Pipelines – Northern Gateway Project.*

- Feeder Pipelines and Other loss before interest and income taxes for 2016 included impairment charges related to Enbridge's 75% joint venture interest in Eddystone Rail attributable to market conditions which impacted volumes at the rail facility.
- Feeder Pipelines and Other EBIT for each year included certain business development costs related to Northern Gateway.

IMPACT OF WILDFIRES IN NORTHEASTERN ALBERTA

During the first week of May 2016, extreme wildfires in northeastern Alberta resulted in the shutdown of a number of oil sands production facilities and the evacuation of more than 80,000 people from the city of Fort McMurray, which serves as a commercial and regional logistics centre for the oil sands region and a home to a significant portion of the oil sands workforce.

Enbridge's facilities in the region were largely unaffected; however, as a precautionary measure on May 4, 2016, the Company temporarily shut down and evacuated its Cheecham terminal and curtailed operations at its Athabasca terminal. The Company also isolated and shut down pipelines in and out of the Cheecham terminal and shut down or curtailed operations on other pipelines it operates in the region.

The Company coordinated with emergency response, public safety and utility officials to restore power and make any necessary repairs to its systems while working closely with producers in the region, and restarted and returned the majority of its regional pipeline systems to normal operation by the end of May 2016.

Oil sands production from facilities in the vicinity of Fort McMurray, Alberta was curtailed longer given the severity and longevity of the wildfires, with oil sands production substantially coming back online by the end of June 2016. On average, Enbridge's mainline system deliveries were lower by approximately 255,000 bpd during the months of May and June 2016, which represented an approximate 10% decrease in throughput compared with the throughput that the Company was delivering prior to the wildfires. In the third quarter of 2016, throughput on the Company's mainline system and overall system utilization strengthened. As a result, the negative impact of reduced system deliveries on revenues impacting the Company's adjusted EBIT and ACFFO for the second half of 2016 remained unchanged since the end of the second quarter of 2016 at approximately $74 million. The Company's adjusted earnings and adjusted earnings per share for the year ended December 31, 2016 were reduced by $26 million and $0.03, respectively.

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 $931 million for the year ended December 31, 2016 compared with $896 million for the year ended December 31, 2015. The year-over-year increase reflected higher throughput driven by strong oil sands production combined with contributions from new assets placed into service in 2015, the most prominent being the expansion of the Company's mainline system completed in the third quarter of 2015 and the reversal and expansion of Line 9B completed in the fourth quarter of 2015, as well as new surcharges for certain system expansions, including the Edmonton to Hardisty Expansion that was completed in the second quarter of 2015. Higher throughput on the Canadian Mainline also reflected increased downstream demand throughout 2016 from the completion of the Southern Access Extension in the fourth quarter of 2015. Adjusted EBIT from Southern Access Extension is reported within Feeder Pipelines and Other. Higher terminalling revenues also contributed to an increase in adjusted EBIT for the year ended December 31, 2016.

The positive effect of increased capacity on Canadian Mainline throughput discussed above was partially offset in the second quarter of 2016 by the impact of extreme wildfires in northeastern Alberta. The wildfires resulted in a curtailment of production from oil sands facilities and certain of the Company's upstream pipelines and terminal facilities were temporarily shut down resulting in a disruption of service on Enbridge's Regional Oil Sands System with corresponding impacts on deliveries to Enbridge's downstream pipelines, including the Canadian Mainline. In the third quarter of 2016, throughput on the Company's mainline system and overall system utilization strengthened. The impact of the wildfires for the year ended December 31, 2016 on Canadian Mainline adjusted EBIT has remained unchanged since the end of the second quarter of 2016 at approximately $30 million. For further details on the wildfires, refer to *Liquids Pipelines – Impact of Wildfires in Northeastern Alberta.*

Year-over-year growth in Canadian Mainline adjusted EBIT was also affected by a lower average Canadian Mainline IJT Residual Benchmark Toll. Effective April 1, 2016, Canadian Mainline IJT Residual Benchmark Toll decreased from US$1.63 to US$1.46, which more than offset the effects of the higher toll charged during the first quarter of 2016. Effective July 1, 2016, Canadian Mainline IJT Residual

Benchmark Toll increased slightly to US$1.47. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher in 2016 due to the recovery of incremental costs associated with EEP's growth projects.

In addition, Canadian Mainline adjusted EBIT reflected the impact of a lower period-over-period exchange rate used to record the Canadian Mainline revenues. The IJT Benchmark Toll and its components are set in United States dollars and the majority of the Company's foreign exchange risk on Canadian Mainline revenue is hedged. For the year ended December 31, 2016, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.07 compared with $1.10 for the corresponding 2015 period.

In addition to the factors noted above, which partially offset the increase in Canadian Mainline adjusted EBIT for the year ended December 31, 2016, higher power costs associated with higher throughput and higher operating and administrative expense to support increased business activities also partially offset the increase.

The decrease in Canadian Mainline IJT Residual Benchmark Toll and lower foreign exchange hedge rate also resulted in a decrease in Canadian Mainline adjusted EBIT for the fourth quarter of 2016 compared with the fourth quarter of 2015.

In 2015, the Company commenced collecting, in its tolls, NEB mandated future abandonment costs from shippers. Approximately $45 million in revenues were recorded for the year ended December 31, 2016 (2015 - $38 million), but these amounts were offset by a corresponding increase in operating and administrative expense in the respective periods. For further details, refer to *Critical Accounting Estimates.*

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 higher rate on hedges used to convert United States dollar denominated revenue. For the year ended December 31, 2015, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.10, compared with $1.02 for the corresponding 2014 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. Also mitigating the impact of a lower Canadian Mainline IJT Residual Benchmark Toll were new surcharges for certain system expansions as noted above. 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.

Supplemental information on Canadian Mainline adjusted earnings for the years ended December 31, 2016, 2015 and 2014 is provided below.

December 31,	**2016**	2015	2014
(United States dollars per barrel)			
IJT Benchmark Toll[1]	**$4.05**	$4.07	$4.02
Lakehead System Local Toll[2]	**$2.58**	$2.44	$2.49
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.47**	$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. Effective July 1, 2016, this toll decreased to US$4.05.

2 The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. 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 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 and effective July 1, 2015, this toll increased to US$2.44. Effective April 1, 2016, this toll increased to US$2.61 and effective July 1, 2016, this toll decreased to US$2.58.

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 July 1, 2014, this toll increased from US$1.81 to US$1.85 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. Effective July 1, 2016, this toll increased to US$1.47.

Throughput Volume[1]

	Q1	Q2	Q3	Q4	Full Year
(thousands of bpd)					
2016	**2,543**	**2,242**	**2,353**	**2,481**	**2,405**
2015	2,210	2,073	2,212	2,243	2,185
2014	1,904	1,968	2,039	2,066	1,995

1 Average throughput volume 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 during 2014 for reversal and expansion. The project was completed and the 300,000 bpd line was placed into service in December 2015. 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 of 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
(thousands of bpd)					
2016	**2,735**	**2,440**	**2,495**	**2,624**	**2,574**
2015	2,330	2,208	2,338	2,388	2,315
2014	2,000	2,088	2,172	2,187	2,113

1 Average throughput volume represents mainline system deliveries to the United States midwest and eastern Canada.

Results of Operations

Lakehead System adjusted EBIT was $1,425 million for the year ended December 31, 2016 compared with $1,108 million for the year ended December 31, 2015. 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 Exchange Rate in 2016 compared with 2015.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$1,074 million for the year ended December 31, 2016 compared with US$868 million for the year ended December 31, 2015. The year-over-year increase reflected higher Lakehead System Local Toll and higher throughput, as well as contributions from new assets placed into service in 2015, the most prominent being the expansion of the Company's mainline system completed in the third quarter of 2015. As discussed under *Canadian Mainline* above, higher throughput on the Lakehead System in 2016 also reflected increased downstream demand resulting from the completion of Southern Access Extension and the reversal and expansion of Line 9B. However, deliveries to the Lakehead System from the Canadian Mainline were lower during the second quarter of 2016, as a result of the northeastern Alberta wildfires. The negative impact of the wildfires for the year ended December 31, 2016 on Lakehead System adjusted EBIT has remained unchanged since the end of the second quarter of 2016 at approximately $38 million. Also partially offsetting the year-over-year increase in adjusted EBIT were higher operating and administrative costs and higher depreciation expense from an increased asset base. Adjusted EBIT for the year ended December 31, 2016 also reflected higher power costs associated with higher throughput.

As noted above, positively impacting Lakehead System adjusted EBIT for the year ended December 31, 2016 was the favourable effect of translating United States dollar earnings at a higher Average Exchange Rate in 2016. The Average Exchange Rate was $1.32 for the year ended December 31, 2016 compared with $1.28 in the corresponding 2015 period. 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 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 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 2015 and 2014, 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 Average Exchange Rate in 2015. The Average Exchange Rate was $1.28 for the year ended December 31, 2015 compared with $1.10 for the comparative period of 2014. As noted above, a portion of Lakehead System United States dollar EBIT was hedged as part of the Company’s enterprise-wide financial risk management program. 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 were 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 Class E 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). The cumulative adjusted EBITDA of the Alberta Clipper Pipeline for fiscal years 2015 and 2016 exceeded the minimum required threshold set under the agreement.

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 line had an initial capacity of 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

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 evaluate the need for additional remediation activities and is performing the necessary 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.

In May 2015, EEP reached a settlement with the Michigan Department of Environmental Quality 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, 2016, EEP's total cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge) since December 31, 2015. This includes a reduction of estimated remediation efforts offset by an increase in civil penalties under the Clean Water Act of the United States, as described below under *Legal and Regulatory Proceedings*. In addition, in the fourth quarter of 2016, the cost accruals were reduced by US$8 million ($1 million after-tax attributable to Enbridge), mainly due to optimization of EEP's remedial investigation reporting and savings related to EEP's residual oil monitoring and maintenance.

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, 2016. 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.

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. In October 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$53 million ($7 million after-tax attributable to Enbridge) before insurance recoveries and including fines and penalties. These costs included emergency response, environmental remediation and cleanup activities with the crude oil release. As at December 31, 2016, 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. On May 1 of each year, the commercial liability insurance program is renewed and includes coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents excluding costs for fines and penalties.

Enbridge has renewed its comprehensive property and liability insurance programs with a liability program aggregate limit of US$900 million, which includes sudden and accidental pollution liability. The insurance programs are effective May 1, 2016 through April 30, 2017. In the unlikely event that 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.

A majority of the costs incurred in connection with the crude oil release for Line 6B, other than fines and penalties, 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, 2016, 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 prior or existing insurance policy. As at December 31, 2016, 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 asserted 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 includes only one insurer.

Of the remaining US$103 million coverage limit, US$85 million was 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. While EEP believes that those costs are eligible for recovery, there can be no assurance that EEP will prevail.

In addition, and separate from the ongoing Line 6B claim, during the year ended December 31, 2016, EEP recorded an insurance recovery of US$10 million ($1 million after-tax attributable to Enbridge) associated with the Line 6A Romeoville crude oil release. This is the total insurance recovery available for the Line 6A incident.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Two actions or claims are pending against Enbridge, EEP or their affiliates in United States 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.

Line 6A and 6B Fines and Penalties

As at December 31, 2016, included in EEP's total estimated costs related to the Line 6B crude oil release were US$69 million in fines and penalties. Of this amount, US$61 million relates to civil penalties under the Clean Water Act of the United States, which EEP fully accrued but has not paid, pending approval of the Consent Decree, as described below.

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 had 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.

Consent Decree

On July 20, 2016, a Consent Decree was filed with the Western District of Michigan Southern Division (the Court). The Consent Decree is EEP's signed settlement agreement with the Environmental Protection Agency (EPA) and the United States Department of Justice regarding Lines 6A and 6B crude oil releases. Pursuant to the Consent Decree, EEP will pay US$62 million in civil penalties: US$61 million in respect of Line 6B and US$1 million in respect of Line 6A. The Consent Decree will take effect upon approval by the Court.

In addition to the monetary fines and penalties discussed above, the Consent Decree calls for replacement of Line 3, which EEP initiated in 2014 and is currently under regulatory review in the State of Minnesota as described in *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Line 3 Replacement Program – United States Line 3 Replacement Program (EEP)*. The Consent Decree contains a variety of injunctive measures, including, but not limited to, enhancements to EEP's comprehensive in-line inspection-based spill prevention program; enhanced measures to protect the Straits of Mackinac; improved leak detection requirements; installation of new valves to control product loss in the event of an incident; continued enhancement of control room operations; and improved spill response capabilities. Collectively, these measures build on continuous improvements implemented since 2010 to EEP's leak detection program, control centre operations and emergency response program. EEP estimates the total cost of these measures to be approximately US$110 million, most of which is already incorporated into existing long-term capital investment and operational expense planning and guidance. Compliance with the terms of the Consent Decree is not expected to materially impact the overall financial performance of EEP or the Company.

REGIONAL OIL SANDS SYSTEM

The Regional Oil Sands System includes three intra-Alberta 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 south of Fort McMurray. The Regional Oil Sands System also includes the Wood Buffalo Pipeline and Norealis Pipeline, each of which provides access for oil sands production from north of Fort McMurray to the Cheecham Terminal. There are also other facilities such as the MacKay River, Christina Lake, Surmont, Long Lake and AOC laterals and related facilities. Regional Oil Sands System currently serves nine 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, depending on crude slate. 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. In January 2017, the Company also completed 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, as discussed under *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Regional Oil Sands Optimization Project (the Fund Group).*

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 the timing of when shippers' commitments commence and expire.

The Woodland Pipeline consists of Line 49 and Line 70 (Woodland Pipeline Extension) which were constructed in phases. In 2012, EPAI entered into a transportation agreement with Imperial Oil Resources Ventures Limited (IORVL) and ExxonMobil Canada Properties (ExxonMobil) to provide for the transportation of blended bitumen from the Kearl oil sands mine to the major Alberta pipeline hub at Edmonton. The construction of the Woodland Pipeline was phased with the Kearl oil sands mine expansion, with the first phase involving construction of a 140-kilometre (87-mile) 36-inch diameter pipeline from the mine to the Cheecham Terminal, and service on the Company's existing Waupisoo Pipeline from Cheecham to the Edmonton area. The completed Woodland Pipeline (Line 49) was placed into service in 2013, commensurate with the start-up of the Kearl oil sands mine. The second phase involved the Woodland Pipeline Extension project, which under a joint venture among EPAI, IORVL and ExxonMobil, extended the Woodland Pipeline south from the Company's Cheecham Terminal to its Edmonton Terminal. The extension involved the construction of a 385-kilometre (239-mile) 36-inch diameter pipeline which was completed and entered service in 2015, adding 379,000 bpd of capacity to the Regional Oil Sands System. The Company has long-term commitments on the Woodland Pipeline.

Results of Operations

Regional Oil Sands System adjusted EBIT for the year ended December 31, 2016 was $384 million compared with $341 million for the year ended December 31, 2015. The year-over-year increase in adjusted EBIT primarily reflected contributions from assets placed into service in the second half of 2015, including the Sunday Creek Terminal and Woodland Pipeline Extension projects that were placed into service in the third quarter of 2015 and the AOC Hangingstone Lateral which was completed in December 2015. Regional Oil Sands System adjusted EBIT also benefitted from higher contracted volumes on Waupisoo Pipeline in the fourth quarter of 2016 compared with the fourth quarter of 2015. However, the year-over-year increase in adjusted EBIT was partially offset by the effects of the wildfires in northeastern Alberta during the second quarter of 2016, as discussed under *Liquids Pipelines – Impact of Wildfires in Northeastern Alberta*, which negatively impacted Regional Oil Sands System adjusted EBIT by approximately $6 million.

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 an estimated 1,300 barrels of light synthetic crude oil on its Line 37 pipeline approximately two kilometres north of Enbridge's Cheecham Terminal. The release was 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 July 29, 2013 after finalization of geotechnical analysis. Investigations into the incident were conducted by the Alberta Energy Regulator and Environment Canada. Each of these investigations was completed and closed by the applicable regulator without any penalties or fines being imposed on Enbridge.

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, 2016, 2015 and 2014, Enbridge recognized insurance recoveries of $5 million, $32 million and $10 million, respectively.

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 Crude Pipeline System (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 7.4 million barrels of crude oil tankage on the Texas Gulf Coast.

The flow direction of Seaway Pipeline was reversed in 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 early 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, the Seaway Pipeline Twin, 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 2006 and an expansion was completed in mid-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. In December 2016, the Company entered into an agreement to sell the Ozark Pipeline to a subsidiary of MPLX LP for cash proceeds of approximately $294 million (US$219 million), including $13 million (US$10 million) in reimbursable costs for additional capital spent by the Company up to the closing date of the transaction. Subject to certain pre-closing conditions, the transaction is expected to close by the end of the first quarter of 2017.

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 are 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, 2016 was $656 million compared with adjusted EBIT of $516 million for the year ended December 31, 2015. 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 Exchange Rate in 2016 compared with 2015.

Excluding the impact of foreign exchange translation to Canadian dollars, Mid-Continent and Gulf Coast adjusted EBIT was US$495 million for the year ended December 31, 2016 compared with US$400 million for the year ended December 31, 2015. The year-over-year increase in adjusted EBIT primarily reflected higher transportation revenues resulting mainly from an increase in the level of committed take-or-pay volumes on Flanagan South, as well as higher tariffs on Flanagan South in the first half of 2016. Throughput on Flanagan South is affected by Canadian Mainline apportionment and the upstream apportionment experienced in the first half of 2015 was partially alleviated in 2016 with the expansion of the Company's mainline system completed in the third quarter of 2015. When committed shippers on Flanagan South are unable to satisfy 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. Partially offsetting the year-over-year increase in adjusted EBIT was lower throughput on Spearhead Pipeline due to a decline in demand for services in the second half of 2016.

Excluding the impact of foreign exchange translation to Canadian dollars, the decline in shippers' demand on Spearhead Pipeline also drove a decrease in Mid-Continent and Gulf Coast adjusted EBIT for the fourth quarter of 2016 compared with the fourth quarter of 2015.

As noted above, positively impacting adjusted EBIT for the year ended December 31, 2016 was the favourable effect of translating United States dollar earnings at a higher Average Exchange Rate in 2016. 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*.

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 Average 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 million 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.

Also positively impacting year-over-year adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Average Exchange Rate in 2015. As noted above, a portion of Mid-Continent and Gulf Coast United States dollar EBIT was hedged as part of the Company's enterprise-wide financial risk management program. 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 February 2014, the FERC rejected Seaway Pipeline's application but also set out a new methodology based on recent appellate court rulings 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 rates application. 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 set the application for hearing before an Administrative Law Judge (ALJ). On December 1, 2016, the ALJ issued its decision which concluded that the Commission should grant the application of Seaway Pipeline for authority to charge market-based rates. The parties may file briefs during the first quarter of 2017, and the Commissioners will review the entire record and issue a decision. There is no timeline for the FERC Commissioners to act and issue a decision.

Additionally, in a February 1, 2016 order, the FERC upheld Seaway Pipeline's current committed rate structure and reversed a prior ALJ decision reducing those rates 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. The FERC accepted the compliance filing by order dated August 17, 2016. Seaway Pipeline has filed new uncommitted rates in accordance with that order. Going forward, Seaway Pipeline's uncommitted rates may be adjusted annually based on the FERC index, unless and until the FERC approves Seaway Pipeline's application for market-based ratemaking authority.

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 mid-2010. Prior to the close of the Canadian Restructuring Plan, the Canadian portion of Southern Lights Pipeline (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 a return on equity (ROE) of 10%. 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, 2016 was $168 million compared with $155 million for the year ended December 31, 2015. The increase in year-over-year adjusted EBIT reflected higher recovery of negotiated depreciation rates in 2016 transportation tolls.

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 Average Exchange Rate in 2015 on the United States component of Southern Lights Pipelines.

BAKKEN SYSTEM

The Bakken System is a joint operation that includes a Canadian entity and a United States entity. The United States portion of the pipeline system extends from Berthold, North Dakota to the International Boundary near North Portal, North Dakota, and connects to the Bakken Canada entity at the border to bring the crude oil into Cromer, Manitoba. 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 80 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.

Tolls and Tariffs

Tariffs on the United States portion of the Bakken System are governed by FERC and include a local tariff. The Canadian portion of the Bakken System is categorized as a Group 2 pipeline, and as such its tolls are regulated by the NEB on a complaint basis. Tolls 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, 2016 was $198 million compared with $213 million for the year ended December 31, 2015. The year-over-year decrease in adjusted EBIT reflected lower rates and lower rail revenues on the United States portion of the Bakken System. The decrease in adjusted EBIT was partially offset by the translation of United States dollar earnings to Canadian dollars at a higher Average Exchange Rate in 2016 compared with 2015.

Excluding the impact of foreign exchange translation to Canadian dollars, adjusted EBIT from Bakken System's United States portion was US$131 million compared with US$155 million for the corresponding 2015 period. The decrease in year-over-year adjusted EBIT for the United States portion of the Bakken System was attributable to lower surcharge revenues as certain surcharge rates subject to an annual adjustment were decreased effective April 1, 2016, as well as lower rail revenues related to EEP's Berthold rail facility due to expired contracts. These negative impacts were partially offset by the effects of higher throughput driven by enhanced downstream capacity on the mainline system and as a result of volumes shifting to pipelines from other higher cost transportation alternatives such as rail.

As noted above, impacting adjusted EBIT for the year ended December 31, 2016 was the favourable effect of translating United States dollar earnings at a higher Average Exchange Rate in 2016. Similar to Lakehead System, a portion of the United States dollar EBIT of the Bakken System in the United States 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*.

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. Within Bakken System adjusted EBIT for the year ended December 31, 2015 was US$155 million (2014 - US$198 million) 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 Average Exchange Rate. As noted above, a portion of the United States dollar EBIT from the Bakken System in the United States was hedged as part of the Company's enterprise-wide financial risk management program. 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, with a capacity to transport 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 delivered Bakken and other light sweet crude oil to Philadelphia area refineries, as well as business development costs related to Liquids Pipelines activities. Due to a significant decrease in price spreads between Bakken crude oil and West Africa/Brent crude oil and increased competition in the region, demand for Eddystone Rail services dropped significantly, resulting in an impairment of this facility in the second quarter of 2016. Feeder Pipelines and Other also includes the Hardisty Contract Terminal and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude pipeline hub in western Canada.

Also reported in Feeder Pipelines and Other results are contributions from the South Prairie Region assets which transport 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. On December 1, 2016, EIPLP completed the sale of the South Prairie Region assets to an unrelated party for cash proceeds of $1.08 billion. The sold assets consisted of certain liquids pipelines and related facilities in southeast Saskatchewan and southwest Manitoba, including the Saskatchewan Gathering and Weyburn gathering systems, as well as the Westspur trunk line. The shipper commercial arrangements and contracts associated with the South Prairie Region assets are expected to remain in place and the Company expects that the crude oil and NGL volumes delivered from the South Prairie Region assets will continue to flow onto Enbridge's Canadian Mainline at Cromer.

Results of Operations

Feeder Pipelines and Other adjusted EBIT for the year ended December 31, 2016 was $196 million compared with $155 million for the year ended December 31, 2015. The year-over-year increase in adjusted EBIT primarily reflected new contributions from Southern Access Extension which was placed into service in the fourth quarter of 2015. These positive contributions were partially offset by a decrease in adjusted EBIT from Eddystone Rail, primarily attributable to market conditions which impacted volumes at the rail facility. Adjusted EBIT for the year ended December 31, 2016 also reflected lower contributions from Toledo Pipeline resulting from refinery turnarounds that negatively impacted volumes in the second and third quarters of 2016, as well as the absence of EBIT from the South Prairie Region assets in the month of December 2016.

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 assets 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 the Olympic pipeline and higher property taxes relating to Toledo Pipeline in the third quarter of 2015.

Eddystone Rail Legal Matter

On February 2, 2017, Enbridge subsidiary Eddystone Rail Company, LLC, (Eddystone) filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania. Eddystone alleges that the defendants transferred valuable assets from Eddystone's counterparty in a maritime contract, so as to avoid outstanding obligations to Eddystone. Eddystone is seeking payment of compensatory and punitive damages in excess of US$140 million. Eddystone's chances of success in connection with the above noted action cannot be predicted and it is possible that Eddystone may not recover any of the amounts sought.

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. In the second quarter of 2016, extreme wildfires in northeastern Alberta resulted in a temporary curtailment of oil sands production from facilities in the vicinity of Fort McMurray, Alberta, resulting in a negative impact on the Company's adjusted EBIT and ACFFO as discussed above. 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.

While take-or-pay and similar contractual arrangements on certain systems serve to mitigate exposure to the risks noted above, 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 Enbridge, the Company is also undertaking the L3R Program, which upon completion, 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. Lastly, in February 2017, the Company acquired an interest in the Bakken Pipeline System, a growth project that will provide North Dakota producers enhanced access to premium light crude oil markets in both the eastern and western United States Gulf Coast. For further details and recent developments on this matter, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Bakken Pipeline System (EEP).*

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 on projects such as the Company's L3R Program, 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.

Renewal of Line 5 Easement

On January 4, 2017, the Tribal Council of the Bad River Band of Lake Superior Tribe of Chippewa Indians (the Band) voted not to renew its interest in certain Line 5 easements through the Bad River Reservation. Line 5 is included within the Company's mainline system. The Band's resolution calls for decommissioning and removal of the pipeline from all Bad River lands and watershed. The Tribal Resolution may impact the Company's ability to operate the pipeline on the Reservation. Since the Band passed the resolution, the parties have held discussions about the possibility of engaging in a facilitated mediation process, with the objective of resolving the Band's concerns on a long-term basis.

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, the United States and internationally 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. 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

	2016	2015	2014
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc. (EGD)	**393**	342	305
Noverco Inc. (Noverco)	**53**	53	45
Other Gas Distribution and Storage	**48**	51	41
Adjusted earnings before interest and income taxes	**494**	446	391
EGD - (warmer)/colder than normal weather	**(18)**	15	48
EGD - employee severance cost adjustment	**10**	6	-
Noverco - changes in unrealized derivative fair value loss	**(6)**	(12)	(7)
Noverco - recognition of regulatory balances	**17**	-	-
Noverco - asset impairment	**(5)**	-	-
Earnings before interest and income taxes	**492**	455	432

Adjusted EBIT from Gas Distribution was $494 million in 2016 compared with $446 million and $391 million in 2015 and 2014, respectively. EGD generated higher adjusted EBIT in 2016 primarily due to an increase in distribution charges arising from growth in EGD's rate base, including customer growth. In 2016, adjusted EBIT from Other Gas Distribution and Storage reflected lower distribution revenues due to warmer weather in the New Brunswick region.

Additional details on items impacting Gas Distribution EBIT include:

- Noverco EBIT for 2016 included an asset impairment in relation to certain long-term assets not eligible for recovery through rates.
- Noverco EBIT for 2016 included the recognition of regulatory assets in relation to employee future benefits.

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 areas 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 2016, 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 allows 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, 2016, EGD's rates were set according to the OEB approved settlement agreement in December 2015 and the final rate order in May 2016. For the year ended December 31, 2015, EGD's rates were set according to the OEB approved settlement agreement in April 2015 and the final rate order in May 2015. 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, 2016, 2015 and 2014, EGD recognized $3 million subject to OEB approval, $7 million and $12 million, respectively, as a return of revenues to customers in relation to the earnings sharing mechanism.

Cap and Trade

Effective January 1, 2017, Ontario commenced a cap and trade program as part of changes intended to lower levels of GHG emissions across the province of Ontario. Under this program, there will be costs related to the GHG emissions from residential and commercial natural gas usage. The Government of Ontario has indicated the funds it collects through the cap and trade program will be allocated to other programs, such as energy conservation, aimed to reduce GHG emissions.

The Government of Ontario requires EGD to acquire GHG allowances to cover the applicable emissions from its residential and commercial customers' usage of natural gas, as well as from emissions from the delivery of natural gas to these customers. Under an interim rate order approved by the OEB, EGD has started to recover cap and trade compliance costs through rates beginning January 1, 2017.

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 provided to facilitate an understanding of EGD's results from operations:

EGD Earnings

	2016	2015	2014
(millions of Canadian dollars)			
Adjusted earnings before interest and income taxes	**393**	342	305
Interest expense	**(178)**	(153)	(150)
Income taxes	**(14)**	(18)	(10)
Adjusting items in respect of:			
Interest expense	**3**	4	-
Income taxes	**(3)**	5	13
Adjusted earnings	**201**	180	158
EGD - (warmer)/colder than normal weather	**(13)**	11	36
EGD - employee severance cost adjustment	**7**	4	-
EGD - changes in unrealized derivative fair value loss	**(2)**	(3)	-
Earnings attributable to common shareholders	**193**	192	194

EGD adjusted earnings for the year ended December 31, 2016 were $201 million compared with $180 million for the year ended December 31, 2015. The year-over-year increase in adjusted earnings primarily reflected higher distribution charges arising from growth in EGD's rate base, including customer growth.

EGD adjusted earnings for the year ended December 31, 2015 were $180 million compared with $158 million for the year ended December 31, 2014. EGD's higher adjusted earnings in 2015 were primarily attributable to an increase in distribution charges that resulted from an increased rate base, as well as customer growth during the year in excess of expectations embedded in rates.

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 Métro Limited Partnership (Gaz Métro), 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 4.38%.

Results of Operations

Noverco adjusted EBIT of $53 million for the year ended December 31, 2016 was comparable with adjusted EBIT of $53 million for the year ended December 31, 2015. Gaz Métro realized higher adjusted operating earnings for 2016 due to a stronger United States dollar, and growth in both its regulated and non-regulated rate base. This was offset by lower wind energy production, as well as lower preferred share dividend income, driven by a lower Government of Canada bond reference rate re-setting. In addition to these factors, there was a decrease in Noverco adjusted EBIT for the fourth quarter of 2016 compared with the fourth quarter of 2015, primarily reflecting higher adjusted EBIT in the fourth quarter of 2015 due to the timing of equity earnings adjustments between quarters.

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 Métro due to a favourable Average Exchange Rate on Gaz Métro'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 11,800 customers and is regulated by the New Brunswick Energy and Utilities Board (EUB).

Results of Operations

Other Gas Distribution and Storage adjusted EBIT was $48 million for the year ended December 31, 2016 compared with $51 million for the year ended December 31, 2015. The decrease in year-over-year adjusted EBIT primarily reflected lower distribution revenues due to warmer weather in the New Brunswick region in 2016.

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
The Company commenced two separate actions in 2012 and 2014, respectively, against the Government of New Brunswick in the New Brunswick courts. The first action sought 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. The second action sought 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.

By agreement finalized on December 16, 2016, the parties fully and finally settled both of the actions. EGNB's franchise for gas distribution in New Brunswick was extended for 25 years beyond its original term ending in 2019, further extendable at EGNB's option for another 25 years after that. The Province of New Brunswick also amended the laws governing gas distribution in the province to, among other things, provide EGNB with the opportunity to recover through rates during the agreed upon franchise extension period up to $145 million of the deferred regulatory asset rendered unavailable by the 2012 legislative and regulatory changes. Of this amount, $100 million is to be recoverable at a fixed rate of $4 million annually starting in the first year of the franchise extension term and the balance is recoverable throughout the future franchise term upon regulatory approval. While Enbridge considers the conditions of settlement and broader legislative changes enacted to achieve it as a favourable development for EGNB's operating environment, EGNB's recovery of the deferred regulatory asset over the future franchise period is not guaranteed and remains subject to the usual operational and regulatory factors applicable to recovery of deferred amounts.

BUSINESS RISKS
The risks identified below are specific to the 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. The Company retains dedicated professional staff and maintains strong relationships with customers, intervenors and regulators. The terms of rate negotiations are reviewed by the Company's legal, regulatory and finance teams. The five-year customized IR Plan approved in 2014 provides a level of stability by having a long-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.

Environmental Regulation
EGD's workers, operations and facilities are subject to municipal, provincial and federal legislation which regulates the protection of the environment and the health and safety of workers. For the environment, this includes the regulation of discharges to air, land and water; the management and disposal of solid and hazardous waste; and the assessment of contaminated sites. Failing to comply with regulations could expose EGD to fines or operating restrictions.

In May 2016, the Government of Ontario passed legislation to establish a cap and trade program in the province of Ontario. Under the legislation, EGD is required to meet GHG compliance obligations by purchasing emission allowances for EGD and its customers. In September 2016, the OEB issued its regulatory framework for the assessment of costs of natural gas utilities' cap and trade activities, addressing regulatory requirements for implementation of cap and trade. In November 2016, EGD filed its compliance plan with the OEB and also received approval of an interim rate order for the recovery of cap and trade compliance costs through rates beginning January 1, 2017.

In 2016, EGD was required to report 2015 GHG emissions to the Ontario Ministry of Environmental and Climate Change from combustion sources only in Ontario, and all reported data was verified by a third party. There were no issues identified for the 2015 reporting year. EGD monitors developments and attends external stakeholder consultations in Ontario. EGD utilizes a carbon data management system to help with the data capture and mandatory and voluntary reporting needs of EGD. EGD continues to publicly report its GHG emissions and will continue to develop internal procedures to identify operational related GHG reductions.

In July 2016, EGD received $58 million from the Government of Ontario for the purpose of carrying out the Green Investment Fund (GIF) program. The purpose of the GIF program is to reduce GHG emissions in the residential sector. EGD's use of the funds is limited to eligible expenditures for the purpose of executing the program. There is no earnings impact related to the GIF program and any unspent funds will be returned to the Government of Ontario at the expiry of the agreement on May 31, 2019, or sooner if the Government of Ontario elects to terminate the agreement at any time prior to its expiration date.

Natural Gas Cost Risk
EGD's regulated business 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.

EGD remains at risk for the actual versus forecast large volume contract commercial and industrial volumes; however, general service volume risk is mitigated for both ratepayers and EGD through a deferral account.

GAS PIPELINES AND PROCESSING

EARNINGS BEFORE INTEREST AND INCOME TAXES

	2016	2015	2014
(millions of Canadian dollars)			
Aux Sable	**(2)**	(3)	45
Alliance Pipeline	**184**	151	135
Vector Pipeline	**31**	28	24
Canadian Midstream	**107**	87	60
Enbridge Offshore Pipelines (Offshore)	**58**	14	12
US Midstream	**5**	73	30
Other	**(17)**	(14)	(13)
Adjusted earnings before interest and income taxes	**366**	336	293
Aux Sable - asset impairment loss	**(37)**	-	-
Aux Sable - accrual for commercial arrangements	**-**	(30)	-
Alliance Pipeline - changes in unrealized derivative fair value gains/(loss)	**10**	(15)	(6)
Alliance Pipeline - derecognition of regulatory balances	**-**	8	-
Offshore - gain on sale of non-core assets	**-**	6	22
US Midstream - changes in unrealized derivative fair value gains/(loss)	**(149)**	(62)	180
US Midstream - goodwill impairment loss	**-**	(440)	-
US Midstream - assets impairment loss	**(14)**	(20)	(18)
US Midstream - loss on disposal of non-core assets	**(4)**	-	-
US Midstream - make-up rights adjustment	**(1)**	1	(4)
US Midstream - transfer of contracts	**-**	(13)	-
Earnings/(loss) before interest and income taxes	**171**	(229)	467

Adjusted EBIT from Gas Pipelines and Processing was $366 million in 2016 compared with adjusted EBIT of $336 million and $293 million in 2015 and 2014. The year-over-year increase in adjusted EBIT was driven primarily by operational efficiencies achieved by Alliance Pipeline, higher adjusted EBIT from Offshore reflecting contributions from Heidelberg Pipeline which was placed into service in January 2016, as well as increase in adjusted EBIT from Canadian Midstream reflecting contributions from the Tupper Plants acquired on April 1, 2016. Partially offsetting these increases were unfavourable market conditions in US Midstream in 2016, resulting in a year-over-year decrease in adjusted EBIT from lower volumes due to reduced drilling by producers.

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

- Aux Sable EBIT for 2016 included an asset impairment charge related to certain underutilized assets at Aux Sable US' NGL extraction and fractionation plant.
- 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 each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to risk manage commodity price exposures.
- US Midstream EBIT for 2016 reflected asset impairment charges in relation to certain non-core trucking assets that the Company sold in the third quarter of 2016.

- 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.

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 an 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. The fractionation facilities at the Channahon Plant were expanded in 2016 in order to handle the increasing NGL content of the Alliance Pipeline's gas stream.

Aux Sable US sells its NGL production from the base plant 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 for the base plant, 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 for the base 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. NGL production associated with the expanded fractionation facilities is sold by a third party marketer, on behalf of Aux Sable, under a three year contract.

Aux Sable also owns facilities upstream of Alliance Pipeline that facilitate deliveries of 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; and Aux Sable Canada's interests in the Montney area of British Columbia, comprising the 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 2016, the Palermo Gas Plant and the Prairie Rose Pipeline were contracted to producers under either take-or-pay, area dedication or fee for service contracts, with contract terms out to 2020. Gas processed at the Palermo Plant in 2016 averaged 53 mmcf/d. Throughput on the Prairie Rose Pipeline in 2016 averaged 100 mmcf/d. In addition, 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 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 believed to be an exceedance of currently permitted limits for Volatile Organic Material. In April 2015, a second NFOV from the EPA was received in connection with this potential exceedance. Aux Sable engaged in discussions with the EPA to evaluate the impacts and ultimate resolution of these issues, including with respect to a draft Consent Decree, and those discussions are continuing. The Consent Decree, when finalized, is not expected to have a material impact.

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim. While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on the Company's consolidated financial position or results of operations.

Results of Operations

Aux Sable reported adjusted loss before interest and taxes of $2 million for the year ended December 31, 2016 comparable with adjusted loss before interest and taxes of $3 million for the year ended December 31, 2015. Aux Sable's operations include both a Canadian and United States component. Within Aux Sable adjusted loss before interest and taxes for the year ended December 31, 2016 was US$2 million from its United States' operations compared with adjusted EBIT of US$4 million for the year ended December 31, 2015.

The slight year-over-year decrease in Aux Sable adjusted loss before interest and taxes was the result of a reduction in gas purchase costs and overhead cost savings within the Canadian business, and lower NGL transport costs within the North Dakota business. These favourable variances were partially offset by higher NGL feedstock costs at the Aux Sable US plant associated with an increase in Rich Gas Premium (RGP) contract volumes. There were no earnings contributions from the upside sharing mechanism in either 2016 or 2015 as a result of low fractionation margins. Aux Sable also reported lower adjusted loss before interest and income taxes for the fourth quarter of 2016 compared with the fourth quarter of 2015, primarily due to lower quarter-over-quarter feedstock supply costs.

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. Within Aux Sable adjusted EBIT for the year ended December 31, 2015 was US$4 million from its United States' operations compared with US$30 million for the year ended December 31, 2014. 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 decreases in adjusted EBIT in 2015 compared with 2014.

Aux Sable Feedstock Supply

Aux Sable secures NGL feedstock for its Channahon Plant primarily through 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. Effective December 1, 2015, Canadian producers 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, notionally located on Alliance Pipeline Canada. Aux Sable purchases RGP gas volumes delivered to the Alliance Trading Point 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 the Alliance Pipeline recontracting, refer to *Gas Pipeline and Processing – Alliance Pipeline – Alliance Pipeline New Services Framework.*

Heat Content Management

Aux Sable is under contract with Alliance Pipeline to provide heat content management services to ensure natural gas exiting the Aux Sable Channahon Plant meets gas quality specifications of downstream transmission and distribution companies, including NGL content (i.e. heat content). Aux Sable monitors the quality of the plant's outlet gas stream on a continuous basis. In 2016, Aux Sable completed an expansion of its fractionation capacity in order to handle increasing volumes of NGLs delivered to the plant. Aux Sable is assessing various options with respect to heat content management as the heat content of the natural gas delivered by Alliance Pipeline is expected to increase in the future.

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.

Alliance Pipeline New Services Framework

Effective December 1, 2015, Alliance Pipeline commenced operations under its New Services Framework. Prior to December 1, 2015, Alliance Pipeline successfully re-contracted its annual firm service capacity with an average contract length of approximately five years. 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. The FERC, as part of its acceptance of Alliance Pipeline US' New Services Framework, 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. In 2016, the FERC expanded the issues set for hearing to include aspects of the Alliance Pipeline US tariff that relate to liquids extraction requirements. The FERC approved Alliance Pipeline US' negotiated rate contracts, which are not set for hearing. Throughout 2016, Alliance Pipeline US conducted settlement hearings with all interested parties, which culminated in the certification of a contested settlement issued to the FERC Commissioners on September 6, 2016, by a FERC ALJ. No Alliance Pipeline US customer contested the settlement. On December 15, 2016, the FERC Commissioners approved essentially all aspects of the contested settlement, except for the liquids extraction matter, which has been set for hearing, with any outcomes to be effective on a prospective basis. Alliance Pipeline has accepted the approved portions of the FERC Commissioners' decision and is seeking rehearing of the decision regarding liquids extraction.

Pursuant to the New Services Framework, Alliance Pipeline retains exposure to potential variability in revenues generated from market based services provided beyond contracted annual firm transport service, as well as certain future costs. 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.

Alliance Pipeline Transportation Services Agreements

Prior to December 1, 2015, Alliance Pipeline Canada had transportation service agreements (TSAs) with shippers for substantially all of its available firm transportation capacity. The TSAs 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-to-equity ratio. Alliance Pipeline US had similar TSAs which allowed for the recovery of the cost of service, which included 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 were an exit fee for shippers that did not elect to extend their transportation contracts. The initial term of the TSAs expired in December 2015, with the exception of a small proportion of shippers that elected to extend their contracts beyond 2015.

Results of Operations

Alliance Pipeline reported adjusted EBIT of $184 million for the year ended December 31, 2016, which represents EBIT from the Company's 50% equity investment in Alliance Pipeline, compared with adjusted EBIT of $151 million for the year ended December 31, 2015. The year-over-year increase in adjusted EBIT was primarily due to lower operating costs and lower depreciation expense as a result of an extension to the useful life of the pipeline assets. Alliance revenues were lower in 2016 resulting from the New Services Framework that commenced in the fourth quarter of 2015; however, earnings from the New Services Framework benefitted from strong demand for seasonal firm service. These positive effects were partially offset by the absence of the 2015 non-renewal fees for Alliance Pipeline US.

Alliance Pipeline reported adjusted EBIT of $151 million for the year ended December 31, 2015 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.

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 this excess capacity environment as Alliance Pipeline is situated in the growing Montney, Duvernay and Bakken areas and was successfully recontracted. Alliance Pipeline is also the only liquids-rich gas export pipeline within the WCSB. Further, Alliance Pipeline accesses large natural gas markets and, following extraction and fractionation at the Aux Sable NGL extraction and fractionation plant, delivers NGL to growing NGL 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 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 Alliance Pipeline. The ability of 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 2016 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, 2016 was $31 million compared with adjusted EBIT of $28 million for the year ended December 31, 2015. Vector's operations include a Canadian and United States component. Within Vector adjusted EBIT for the year ended December 31, 2016 was US$21 million from its United States' operations compared with adjusted EBIT of US$20 million for the year ended December 31, 2015. Excluding the impact of foreign exchange translation to Canadian dollars, Vector adjusted EBIT, which represents EBIT from the Company's equity investment in Vector, was slightly higher for the year ended December 31, 2016 compared with the year ended December 31, 2015. The positive effect of lower interest costs due to a declining debt balance, more than offset lower year-over-year transportation revenues. Initial long-haul transportation contracts terminated in 2016 as expected and capacity was re-contracted at lower market based rates.

Vector adjusted EBIT for the year ended December 31, 2015 was $28 million compared with $24 million for the year ended December 31, 2014. 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 stronger United States dollar compared with the Canadian dollar. EBIT from the United States portion of Vector was translated at a higher Average 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 fully contracted under firm service agreements at December 31, 2016. Long and short haul transportation service on the U.S segment of the system is contracted with shippers under a combination of both FERC approved negotiated rate service agreements and FERC tariff recourse rate service agreements.

In 2016, the remaining initial long-term firm service shippers, representing 255 mmcf/d, restructured their agreements and extended their terms to 2020 and beyond. There are now no more initial long-term contracts with early termination or annual extension rights.

In late 2014 and early 2015, Vector signed precedent agreements with both the proposed NEXUS Pipeline (Nexus) project and Energy Transfer Partners L.P.'s Rover Pipeline (Rover) project, to provide transportation service to the Dawn natural gas market hub. The Rover project received FERC approval on February 2, 2017 and is expected to commence deliveries into Vector in late 2017. The Nexus project is expected to receive FERC approval later in 2017, the timing of which will delay the start of construction, thereby delaying initial deliveries into Vector until the second half of 2018.

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 2016, the FERC-approved maximum tariff rates included an underlying weighted average after-tax ROE component of 12.75%. 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 2016, maximum tolls on the Canadian portion include an ROE component of 10.48% 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 both the Rover and Nexus proposed pipeline projects that will extend back to the Marcellus/Utica supply basin. Rover is expected to commence deliveries into Vector in late 2017, and Nexus in 2018. Once both projects are in service, these arrangements will effectively fill all available delivery capacity to Dawn, Ontario from current contract roll-offs scheduled through 2019. Current firm service contracts that amount to approximately 60% of long haul capacity are scheduled to expire during 2017 and 2018.

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, as discussed above, Vector is expected to commence firm service transport based on precedent agreements with respect to the 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.

CANADIAN MIDSTREAM
At December 31, 2016, Canadian Midstream consisted of the wholly-owned Tupper Plants located within the Montney shale play in northeastern British Columbia, the Company's 71% interest 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 interests in the Pipestone and Sexsmith gathering systems (together, Pipestone and Sexsmith). The Company has almost 100% interest in Pipestone and the primary producer and operator of Pipestone holds a nominal 0.01% interest. The Company also has varying interests (55% to 100%) in Sexsmith and its related sour gas gathering, compression and NGL handling facilities, located in the Peace River Arch region of northwest Alberta. Enbridge is the operator of the Tupper Plants and 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.

In April 2016, Enbridge acquired the Tupper Plants as described under *Growth Projects – Commercially Secured Projects.* The Tupper Plants are designed to process low hydrogen sulfide natural gas and remove a modest level of NGL in order to meet downstream natural gas pipeline specifications.

Phase 1 of Cabin is currently 98% completed. Cabin producers are expected to request the Company to commission and start-up Phase 1 once the 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.

Results of Operations

Canadian Midstream adjusted EBIT was $107 million for the year ended December 31, 2016 compared with adjusted EBIT of $87 million for the year ended December 31, 2015. The increase in year-over-year adjusted EBIT reflected contributions from the Tupper Plants following their acquisition on April 1, 2016. Contributions from the Company's investment in Cabin, Pipestone and Sexsmith were comparable year-over-year.

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 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

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.

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.

Pipestone and Sexsmith are located within the liquids-rich Peace River Arch region which has seen significant development by area producers. In 2016, throughput volumes exceeded take-or-pay levels.

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. These pipelines are located in four major corridors in the Gulf of Mexico, extending to deepwater developments, and include almost 2,100 kilometres (1,300 miles) of underwater pipe and onshore facilities with total capacity of approximately 6.5 bcf/d.

Results of Operations

Offshore adjusted EBIT was $58 million for the year ended December 31, 2016 compared with adjusted EBIT of $14 million for the year ended December 31, 2015. Excluding the impact of foreign exchange translation to Canadian dollars, Offshore adjusted EBIT for the year ended December 31, 2016 was US$44 million compared with US$11 million for the year ended December 31, 2015. The year-over-year increase in Offshore adjusted EBIT primarily reflected contributions from Heidelberg Pipeline which was placed into service in January 2016 and an increase in volumes in the Mississippi Canyon Gas Pipeline in the first half of 2016, partially offset by a decrease in volumes in the Garden Banks Gas Pipeline in the second half of 2016. Finally, the higher year-over-year adjusted EBIT also reflected the favourable impact of translating United States dollar earnings at a higher Average Exchange Rate in 2016.

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 of US$11 million for the year ended December 31, 2015 was comparable with US$12 million for the year ended December 31, 2014. 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, the higher adjusted EBIT also reflected the favourable impact of translating United States dollar earnings at a higher Average 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 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 maximum daily quantity schedule to match current delivery expectations. The majority of long-term contracts have fixed transport rates, 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, 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 meet or exceed 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, associated deductibles and availability of insurance coverage and as a result, the Company does not carry windstorm insurance coverage. Enbridge facilities are engineered to withstand hurricane forces and regular monitoring of extreme 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 rail and liquids marketing operations. Enbridge's ownership interest in US Midstream, held through EEP, was 19.0% as at December 31, 2016 (December 31, 2015 - 19.2%).

Results of Operations

US Midstream adjusted EBIT was $5 million for the year ended December 31, 2016 compared with $73 million for the year ended December 31, 2015. Excluding the impact of foreign exchange translation to Canadian dollars, US Midstream adjusted EBIT was US$4 million for the year ended December 31, 2016 compared with US$57 million for the year ended December 31, 2015. The year-over-year decreases in US Midstream adjusted EBIT reflected lower volumes primarily attributable to the continued low commodity price environment which resulted in reduced drilling by producers. The decrease in adjusted EBIT was partially offset by lower operating costs.

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 Average Exchange Rate in 2015 compared with 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.

As noted above, impacting year-over-year adjusted EBIT is the effect of translating United States dollar earnings to Canadian dollars. The Average Exchange Rate fluctuates period-over-period with a resulting impact on adjusted EBIT. 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 and Privatization

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).

As discussed under *United States Sponsored Vehicle Strategy,* in May 2016, EEP announced that it was exploring various strategic alternatives for its investments in MEP and Midcoast Operating L.P., the operating subsidiary of MEP. On January 27, 2017, Enbridge announced that it had entered into a merger agreement through a wholly-owned subsidiary, whereby it will take private MEP by acquiring all of the outstanding publicly-held common units of MEP for total consideration of approximately US$170 million in the second quarter of 2017.

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.

Economic Regulation

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 partially mitigated 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

	2016	2015	2014
(millions of Canadian dollars)			
Green Power and Transmission	**165**	175	151
Adjusted earnings before interest and income taxes	**165**	175	151
Green Power and Transmission - changes in unrealized derivative fair value gains/(loss)	**2**	2	(2)
Green Power and Transmission - investment impairment loss	**(13)**	-	-
Earnings before interest and income taxes	**154**	177	149

Green Power and Transmission includes approximately 1,900 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 780 MW of net power generating capacity comes from wind farms located in the states of Colorado, Texas, Indiana and West Virginia, including the 103-MW New Creek Wind Project which entered service in late December 2016. The vast majority of the power produced from these wind farms is sold under long-term PPAs. 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 $165 million for the year ended December 31, 2016 compared with adjusted EBIT of $175 million for the year ended December 31, 2015. Within Green Power and Transmission adjusted EBIT for the year ended December 31, 2016 was US$27 million (2015 - US$27 million) from its United States' operations.

Excluding the impact of foreign exchange translation to Canadian dollars, adjusted EBIT decreased year-over-year as a result of disruptions at certain eastern Canadian wind farms in the first quarter and fourth quarter of 2016 due to weather conditions which caused icing of blades, as well as weaker wind resources experienced at certain facilities in Canada. These negative effects were partially offset by stronger wind resources at the Company's United States wind farms during the second half of 2016.

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. However, the United States operations experienced a slight decrease in adjusted EBIT due to weaker wind resources at Cedar Point wind farm.

Adjusted EBIT for the years ended December 31, 2016 and 2015 reflected the favourable impact of translating United States dollar earnings at a higher year-over-year Average Exchange Rate in each of 2016 and 2015 on the United States businesses within Green Power and Transmission.

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 are 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 and cash flows for the Company. Additionally, inefficiencies or interruptions of Green Power facilities due to operational disturbances or outages resulting from weather conditions or other factors, 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 PPAs 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

	2016	2015	2014
(millions of Canadian dollars)			
Energy Services	**28**	61	42
Adjusted earnings before interest and income taxes	**28**	61	42
Energy Services - changes in unrealized derivative fair value gains/(loss)	**(205)**	264	688
Energy Services - custom duties paid on settlement of dispute	**(8)**	-	-
Earnings/(loss) before interest and income taxes	**(185)**	325	730

Following are additional details on Energy Services EBIT:

- Changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and exposure to movements in commodity prices on the value of inventory.
- Adjusted EBIT for 2014 excluded a realized loss in 2014 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 $28 million for the year ended December 31, 2016 compared with adjusted EBIT of $61 million for the year ended December 31, 2015. Reported within Energy Services adjusted EBIT for the year ended 2016 was US$32 million (2015 - US$31 million) from its United States operations.

Excluding the year-over-year favourable impact of foreign exchange translation to Canadian dollars, the decrease in adjusted EBIT in 2016 reflected weaker performance from Energy Services' Canadian and United States operations during the first half of 2016. The compression of certain crude oil location and quality differentials and the impact of a weaker NGL market drove a year-over-year decrease in adjusted EBIT. This decrease was partially offset by the translation of United States dollar earnings to Canadian dollars at a higher Average Exchange Rate in 2016, as well as positive contributions from increased crude oil storage opportunities in the second half of 2016. The positive crude oil storage opportunities were also a driver for the increase in adjusted EBIT in the fourth quarter of 2016 compared with 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 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. Reported 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 year-over-year favourable impact of foreign exchange translation to Canadian dollars, the increase in adjusted EBIT in 2015 compared with 2014 reflected strong refinery demand for certain crude oil feedstock leading to more favourable storage management opportunities. Also contributing to the year-over-year increase in adjusted EBIT were 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.

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 and cash flow 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, which require 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

	2016	2015	2014
(millions of Canadian dollars)			
Operating and administrative	**(101)**	(74)	(80)
Realized foreign exchange derivative gains/(loss)	**(297)**	(238)	8
Other	**49**	66	12
Adjusted loss before interest and income taxes	**(349)**	(246)	(60)
Changes in unrealized derivative fair value gains/(loss)	**417**	(694)	(387)
Unrealized intercompany foreign exchange gains/(loss)	**(43)**	131	16
Employee severance and restructuring costs	**(92)**	(47)	(6)
Project development and transaction costs	**(81)**	-	-
Drop down transaction costs	**-**	(41)	(35)
Asset impairment loss	**-**	(2)	-
Gain on sale of assets	**-**	-	16
Loss before interest and income taxes	**(148)**	(899)	(456)

Items impacting Eliminations and Other EBIT include:

- Employee severance and restructuring costs incurred in 2016 in relation to the Company's Building Our Energy Future initiative. For additional information, refer to *Corporate Vision and Strategy – Strategy – Maintain the Foundation – Attract, Retain and Develop Highly Capable People.*
- Project development and transaction costs incurred in 2016 in relation to the proposed Merger Transaction. For additional information, refer to *Merger Agreement with Spectra Energy.*

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, 2016 was a realized loss of $297 million (2015 - $238 million loss; 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 2016 was US$1,044 million (2015 - US$952 million; 2014 - US$910 million) with an average price to sell United States dollars for Canadian dollars at $1.04 (2015 - $1.03; 2014 - $1.11). The Average Exchange Rate for the year ended December 31, 2016 was $1.32 (2015 - $1.28; 2014 - $1.10).

As the hedge rate was lower than the Average Exchange Rate in 2016 and 2015, the Company recognized realized hedge losses in each of these periods. The realized hedge loss for the year ended December 31, 2016 was greater than the comparative 2015 period due to higher notional amount of foreign currency derivatives and a greater unfavourable spread between the Average Exchange Rate and hedge rate. The realized loss in Eliminations and Other serves to partially offset the positive effect of translating the earnings performance of United States dollar denominated businesses at the 2016 Average Exchange Rate of $1.32 which is reflected in the reported EBIT of the applicable business segments. In 2014, the hedge rate approximated the Average 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 businesses at an enterprise-wide level. Gains and losses arising on settlements of foreign exchange derivatives hedging transactional exposure 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 dollar 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.*

Eliminations and Other adjusted EBIT also reflected higher operating and administrative costs in 2016 primarily due to higher depreciation expense resulting from additions to intangible assets, computer hardware and leasehold improvements, as well as lower recoveries from other business segments.

Other adjusted EBIT decreased from $66 million for the year ended December 31, 2015 to $49 million for the year ended December 31, 2016. The decrease in adjusted EBIT reflected realized foreign exchange losses from the translation of certain intercompany transactions. The increase in adjusted EBIT in 2015 when compared with the corresponding 2014 period was the result of 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 capital markets issuances, commercial paper and/or credit facility draws to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. The Company targets to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial 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. For additional information, refer to *Sponsored Vehicles* below.

CAPITAL MARKET ACCESS

The Company and its self-funding subsidiaries ensure ready access to capital markets, subject to market conditions, 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 capital market issuances in 2016:

Entity	Type of Issuance	Amount
(millions of Canadian dollars, unless stated otherwise)		
Enbridge	Common shares	2,300
Enbridge	Preference shares	750
Enbridge	United States dollar term notes	US$1,500
Enbridge	Fixed-to-floating subordinated term notes	US$750
ENF	Common shares	575
EGD	Medium-term notes	300
EPI (via the Fund Group)	Medium-term notes	800

Bank Credit and Liquidity

To ensure ongoing liquidity and 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, 2016 and 2015.

		2016			2015
December 31,	Maturity	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge	2017-2020	**8,183**	**4,700**	**3,483**	6,988
Enbridge (U.S.) Inc.	2018-2019	**3,934**	**126**	**3,808**	4,470
EEP	2018-2020	**3,525**	**2,293**	**1,232**	3,598
EGD	2018-2019	**1,017**	**360**	**657**	1,010
The Fund	2019	**1,500**	**236**	**1,264**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2018	**27**	**-**	**27**	28
EPI	2018	**3,000**	**1,032**	**1,968**	3,000
Enbridge Southern Lights LP	2018	**5**	**-**	**5**	5
MEP	2018	**900**	**564**	**336**	1,121
Total committed credit facilities		**22,091**	**9,311**	**12,780**	21,720

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

In 2016, the Company further diversified its access to funding through the establishment of two term credit facilities with syndicates of Asian banks for a total commitment of $968 million. These facilities were fully drawn upon in the second quarter of 2016 and provided a cost effective source of United States dollar term debt financing when compared with the cost of term debt financing in the United States public market at the time.

In addition to the committed credit facilities noted above, the Company also maintains $335 million (2015 - $349 million) of uncommitted demand facilities, of which $177 million (2015 - $185 million) were unutilized as at December 31, 2016.

The Company's net available liquidity of $14,274 million at December 31, 2016 was inclusive of $2,117 million of unrestricted cash and cash equivalents and net of bank indebtedness of $623 million as reported on the Consolidated Statements of Financial Position.

The Company's credit facility agreements and term debt indentures 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, 2016, 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, 2016, the Company's debt capitalization ratio was 62.1% compared with 65.5% as at December 31, 2015.

Following the Company's announcement of the Merger Transaction, the Company's credit ratings were affirmed as follows:

- DBRS Limited (DBRS) confirmed the Company's issuer rating and medium-term notes and unsecured debentures rating of BBB (high), preference share rating of Pfd-3 (high) and commercial paper rating of R-2 (high), but changed their rating outlook from stable to under review, with developing implications.

- Moody's Investor Services, Inc. affirmed the Company's issuer rating and medium-term notes and unsecured debt rating of Baa2, preference share rating of Ba1 and commercial paper rating of P-2, and retained a negative outlook.
- Standard & Poor's Rating Services (S&P) affirmed the Company's corporate credit rating and unsecured debt rating of BBB+, preference share rating of P-2 (low) and commercial paper rating of A-1 (low), and reaffirmed a stable outlook. S&P also affirmed the Company's global overall short-term rating of A-2. S&P also upgraded Enbridge's pro forma financial risk profile to "significant" from "aggressive" due to the improved risk profile and projected credit metrics of the combined Company.

Enbridge's solid investment grade credit rating is 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. The Company continues to execute its growth capital program and believes that it continues to have access to capital markets in both Canada and the United States to adequately fund the execution of its growth capital program.

The Company invests surplus cash in short-term investment grade money market instruments with highly creditworthy counterparties. Short-term investments were $800 million as at December 31, 2016 compared with $27 million as at December 31, 2015. The higher short-term investment balances at the end of 2016 reflect the temporary investment of a portion of capital markets funding undertaken by the Company in the fourth quarter pending its redeployment in growth capital program. At December 31, 2016, all short-term money market investments were rated not less than R-1 (low), A and A2 by DBRS, S&P and Moody's Investor Services, Inc., respectively.

There are no material restrictions on the Company's cash with the exception of the restricted cash of $68 million, which includes EGD's receipt of cash from the Government of Ontario to fund its GIF program, 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, 2016 and 2015 the Company had a negative working capital position of $456 million and $1,227 million, respectively. In both periods, the major contributing factor to the negative working capital position was the ongoing funding of the Company's growth capital program.

To address this negative working capital position, the Company maintains significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due. As at December 31, 2016, the net available liquidity totalled $14,274 million (2015 - $10,325 million). It is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

December 31,	**2016**	2015
(millions of Canadian dollars)		
Cash and cash equivalents[1]	**2,185**	1,049
Accounts receivable and other[2]	**4,992**	5,437
Inventory	**1,233**	1,111
Bank indebtedness	**(623)**	(361)
Short-term borrowings	**(351)**	(599)
Accounts payable and other[3]	**(7,417)**	(7,399)
Interest payable	**(333)**	(324)
Environmental liabilities	**(142)**	(141)
Working capital	**(456)**	(1,227)

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

SOURCES AND USES OF CASH

December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Operating activities	**5,211**	4,571	2,547
Investing activities	**(5,192)**	(7,933)	(11,891)
Financing activities	**1,102**	2,973	9,770
Effect of translation of foreign denominated cash and cash equivalents	**(19)**	143	59
Increase/(decrease) in cash and cash equivalents	**1,102**	(246)	485

Significant sources and uses of cash for the years ended December 31, 2016 and December 31, 2015 are summarized below:

Operating Activities

2016

- The growth in cash flow delivered by operations in 2016 is a reflection of the positive operating factors discussed under *Performance Overview – Adjusted EBIT* and *Performance Overview – Adjusted Earnings*, which primarily included stronger contributions from the Liquids Pipelines segment, partially offset by higher financing costs resulting from the incurrence of incremental debt to fund asset growth and the impact of refinancing construction debt with longer-term debt financing.
- Changes in operating assets and liabilities included within operating activities were $358 million for the year ended December 31, 2016 compared with $645 million for the comparative 2015 year. Enbridge's operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, general variations in activity levels within the Company's businesses, as well as timing of cash receipts and payments.

2015

- The growth in cash flow delivered by operations in 2015 compared with 2014 is also a reflection of the positive operating factors discussed under *Performance Overview – Adjusted EBIT* and *Performance Overview – Adjusted Earnings*, which primarily include higher throughput on the Canadian Mainline, higher volumes and tolls on the Lakehead System, contributions from new liquids pipeline assets placed into service in recent years and strong refinery demand for crude oil feedstock leading to more favourable storage management opportunities for Energy Services. Partially offsetting these positive factors were higher financing costs associated with funding of the Company's growth program.
- Changes in operating assets and liabilities included within operating activities resulted in a cash outflow of $645 million for the year ended December 31, 2015 compared with an outflow of $1,699 million for the comparative 2014 period. The favourable variance for changes in operating assets and liabilities was 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. Partially offsetting the favourable variance was higher inventory in Energy Services, as a result of increased activity in conjunction with the completion of the Seaway Pipeline Twin and Flanagan South projects in late 2014.

Investing Activities
The Company continues with the execution of its growth capital program which is further described in *Growth Projects – Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

A summary of additions to property, plant and equipment for the years ended December 31, 2016, 2015 and 2014 is set out below:

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Liquids Pipelines	**3,956**	5,882	8,911
Gas Distribution	**713**	858	610
Gas Pipelines and Processing	**176**	385	593
Green Power and Transmission	**251**	68	333
Energy Services	**-**	-	3
Eliminations and Other	**32**	80	74
Total capital expenditures	**5,128**	7,273	10,524

2016

- The timing of projects approval, construction and in-service dates impact the timing of cash requirements. For the year ended December 31, 2016, additions to property, plant and equipment resulted in cash expenditures of $5,128 million compared with $7,273 million for the year ended December 31, 2015. The year-over-year decrease reflected the successful completion of growth projects in 2015, including the Edmonton to Hardisty Expansion, Southern Access Extension and phases of the Eastern Access Program.
- Also contributing to the decrease in year-over-year cash used in investing activities was proceeds received from disposition of assets. For the year ended December 31, 2016, proceeds from dispositions were $1,379 million compared with $146 million for the year ended December 31, 2015. The majority of the proceeds in 2016 related to the sale of the South Prairie Region assets completed in December 2016.
- Partially offsetting the above factors was higher spending by the Company in 2016 for acquisitions. During the second quarter of 2016, the Company made an initial equity investment in and advanced an affiliate loan to acquire a 50% interest in a French offshore wind development company and fund the ongoing development costs of that company.

2015

- For the year ended December 31, 2015, additions to property, plant and equipment resulted in cash spending of $7,273 million compared with $10,524 million for the year ended December 31, 2014. As previously noted, the timing of growth projects' approval, construction and in-service dates impact the timing of cash requirements. In 2014, higher capital additions reflected expenditures on significant growth projects brought into service, including Flanagan South, as well as ongoing expenditures on major components of the Eastern Access Program and Edmonton to Hardisty Expansion project, which were completed in 2015.

Financing Activities
2016

- The Company's financing requirements decreased for the year ended December 31, 2016 compared with December 31, 2015, primarily reflecting lower expenditures on growth capital projects and the proceeds of asset sales. The Company's funding requirements are a reflection of the timing of various growth projects.
- In 2016, the Company's overall debt decreased by $149 million compared with an overall increase in debt of $3,663 million in 2015. The decrease was mainly due to lower debt requirements resulting from the timing of completion of various growth projects and other sources of funds, primarily the proceeds from the Company's common share issuance in March 2016, which were partly utilized to reduce the Company's credit facilities and commercial paper draws.
- The increase in common share dividends paid in 2016 was attributable to the increase in the common share dividend rate effective March 2016 and higher number of common shares outstanding primarily as a result of the common share issuance noted above.

- Distributions to redeemable noncontrolling interests in the Fund Group increased during 2016 compared with the corresponding 2015 period mainly due to a higher per share distribution rate and a larger number of public shares outstanding in ENF. Higher distributions to noncontrolling interests in EEP reflected an increase to the per unit distribution in the first half of 2016 as well as the effects of a strengthening United States dollar versus the Canadian dollar.

2015

- The Company's financing requirements in 2015 were lower compared with the corresponding period and reflected lower capital requirements as a result of a combination of timing of capital expenditures and increased cash flow generation from operations. Additionally, during 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.
- In 2015, the Company increased its overall debt by $3,663 million compared with $9,000 million in 2014. The higher debt issuance in 2014 reflected greater financing needs in support of the Company's growth program. Funding of the Company's growth program was also achieved through the issuance of preference shares. In 2014, the Company issued $1,365 million of preference shares, whereas there were no preference shares issued in 2015. The overall increase in common shares and preference shares outstanding, along with an increase in the common share dividend rate, resulted in a higher amount of dividends paid by the Company in 2015 compared with 2014.
- Included within Financing Activities are contributions and distributions to 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.

Preference Share Issuances

Since July 2011, the Company has issued 290 million preference shares for gross proceeds of approximately $7,277 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	4.00%	$1.00	$25	June 1, 2017	Series C
Series D[5]	$450 million	4.00%	$1.00	$25	March 1, 2018	Series E
Series F[5]	$500 million	4.00%	$1.00	$25	June 1, 2018	Series G
Series H[5]	$350 million	4.00%	$1.00	$25	September 1, 2018	Series I
Series J[5]	US$200 million	4.00%	US$1.00	US$25	June 1, 2017	Series K
Series L[5]	US$400 million	4.00%	US$1.00	US$25	September 1, 2017	Series M
Series N[5]	$450 million	4.00%	$1.00	$25	December 1, 2018	Series O
Series P[5]	$400 million	4.00%	$1.00	$25	March 1, 2019	Series Q
Series R[5]	$400 million	4.00%	$1.00	$25	June 1, 2019	Series S
Series 1[5]	US$400 million	4.00%	US$1.00	US$25	June 1, 2018	Series 2
Series 3[5]	$600 million	4.00%	$1.00	$25	September 1, 2019	Series 4
Series 5[5]	US$200 million	4.40%	US$1.10	US$25	March 1, 2019	Series 6
Series 7[5]	$250 million	4.40%	$1.10	$25	March 1, 2019	Series 8
Series 9[5]	$275 million	4.40%	$1.10	$25	December 1, 2019	Series 10
Series 11[5]	$500 million	4.40%	$1.10	$25	March 1, 2020	Series 12
Series 13[5]	$350 million	4.40%	$1.10	$25	June 1, 2020	Series 14
Series 15[5]	$275 million	4.40%	$1.10	$25	September 1, 2020	Series 16
Series 17[5]	$750 million	5.15%	$1.29	$25	March 1, 2022	Series 18

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board. With the exception of Series A Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15%. No other series of Preference Shares has this feature.*

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 *With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect 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), 2.7% (Series 16), 4.1% (Series 18); 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 – Sources and Uses of Cash – Dividend Reinvestment and Share Purchase Plan.*

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 were 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 additional 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, 2016, dividends declared were $1,945 million (2015 - $1,596 million), of which $1,150 million (2015 - $950 million) were paid in cash and reflected in financing activities. The remaining $795 million (2015 - $646 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, 2016 and 2015, 40.9% and 40.5%, respectively, of total dividends declared were reinvested.

On January 5, 2017, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2017 to shareholders of record on February 15, 2017.

Common Shares	$0.58300
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
Preference Shares, Series 17	$0.34570

SPONSORED VEHICLES
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 for a total consideration of $1.8 billion. For further details, refer to *The Fund Group 2014 Drop Down Transaction.* In September 2015, the Company completed the Canadian Restructuring Plan. For further details, refer to *Canadian Restructuring Plan.*

EEP
In the United States, the restructuring of EEP's equity was completed in 2014 as discussed below. 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.*

In May 2016, EEP announced that it was exploring various strategic alternatives for its investments in Midcoast Operating Partners, L.P. and MEP. On January 27, 2017, Enbridge announced that it had entered into a merger agreement through a wholly-owned subsidiary, whereby it will take private MEP by acquiring all of the outstanding publicly-held common units of MEP for total consideration of approximately US$170 million in the second quarter of 2017. For additional information on Enbridge's on-going strategic review of EEP, refer to *United States Sponsored Vehicle Strategy.*

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, 2016, Enbridge's economic interest in EEP was 35.3% (2015 - 35.7%, 2014 - 33.7%). The Company's average economic interest in EEP during 2016 was 35.5% (2015 - 36.0%, 2014 - 27.3%). 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% 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. 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 (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 Incentive Distribution Units are 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 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 July 2015, EEP further increased its quarterly distribution to US$0.5830.

In 2016, Enbridge received from EEP, incentive distributions of US$21 million (2015 - US$19 million, 2014 - US$39 million). Also in 2016, Enbridge received distributions of US$196 million from Class D units (2015 - US$195 million, 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]	31,967	2,599	3,036	4,714	21,618
Capital and operating leases [2]	987	118	145	130	594
Long-term contracts[4]	11,055	3,714	2,785	2,130	2,426
Pension obligations[3]	148	148	-	-	-
Total contractual obligations	44,157	6,579	5,966	6,974	24,638

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 *Includes land leases.*

3 *Assumes only required payments will be made into the pension plans in 2017. Contributions are made in accordance with independent actuarial valuations as at December 31, 2016. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.*

4 *Includes commitments for transportation service agreements totaling $618 million which assume a light to heavy crude oil ratio of 80:20 on certain pipelines and a power charge of $0.06 per barrel.*

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 $1,903 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
Preference Shares, Series 17	30,000,000	March 1. 2022	Series 18

COMMON SHARES

	Number
Common Shares - issued and outstanding (voting equity shares)	943,186,589
Stock Options - issued and outstanding (20,738,364 vested)	35,751,751

1 *Outstanding share data information is provided as at February 6, 2017.*

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, as discussed under the terms of the respective Preference Shares.*

QUARTERLY FINANCIAL INFORMATION

2016	Q1	Q2	Q3	Q4	Total
(millions of Canadian dollars, except for per share amounts)					
Revenues	**8,795**	**7,939**	**8,488**	**9,338**	**34,560**
Earnings/(loss) attributable to common shareholders	**1,213**	**301**	**(103)**	**365**	**1,776**
Earnings/(loss) per common share	**1.38**	**0.33**	**(0.11)**	**0.39**	**1.95**
Diluted earnings/(loss) per common share	**1.38**	**0.33**	**(0.11)**	**0.39**	**1.93**
Dividends paid per common share	**0.530**	**0.530**	**0.530**	**0.530**	**2.120**
EGD - warmer/(colder) than normal weather[1]	**13**	**(7)**	**-**	**7**	**13**
Changes in unrealized derivative fair value (gains)/loss[1]	**(652)**	**1**	**32**	**189**	**(430)**

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[1]	(33)	6	-	16	(11)
Changes in unrealized derivative fair value (gains)/loss[1]	977	(296)	654	45	1,380

1 *Included in earnings/(loss) attributable to common shareholders.*

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 2016 was a gain of $520 million (after-tax attributable to Enbridge) on the disposal of South Prairie Region assets within the Liquids Pipelines segment.
- Included in the fourth quarter of 2016 was an asset impairment charge of $272 million (after-tax attributable to Enbridge) related to Northern Gateway. For additional information, refer to *Other Announced Projects Under Development – Liquids Pipelines – Northern Gateway Project.*

- Included in the fourth quarter of 2016 were employee severance and restructuring costs incurred in relation to the Company's Building Our Energy Future initiative, with a net charge of $37 million to earnings. For additional information, refer to *Corporate Vision and Strategy – Strategy – Maintain the Foundation – Attract, Retain and Develop Highly Capable People.*
- Included in the fourth quarter of 2016 and second quarter of 2015 were the tax impacts 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 remained in consolidated earnings and resulted in charges of $11 million and $39 million, respectively.
- In the third quarter of 2016, impairment charges of $1,000 million ($81 million after-tax attributable to Enbridge), including related project costs of $8 million, were recognized in relation to EEP's Sandpiper Project as discussed in *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Sandpiper Project (EEP)*. In the fourth quarter of 2016, additional project costs of $4 million (nil after-tax attributable to Enbridge) were recognized.
- Included in the second and third quarters of 2016 were after-tax costs attributable to Enbridge of $12 million and $10 million, respectively, incurred in relation to the restart of certain of Enbridge's pipelines and facilities following the northeastern Alberta wildfires.
- Included in the second quarter of 2016 were impairment charges of $103 million (after-tax attributable to Enbridge) related to Enbridge's 75% joint venture interest in Eddystone Rail, attributable to market conditions which impacted volumes at the rail facility.
- Included in earnings are after-tax insurance recoveries associated with the Line 37 crude oil release which occurred in June 2013. Insurance recoveries of $3 million were recognized in the first quarter of 2016, and $9 million and $13 million were recognized in each of the first and fourth quarters of 2015, respectively. Earnings also reflected after-tax costs of $6 million in the second quarter of 2015 in connection with the Line 37 crude oil release.
- 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 transfer of Enbridge's Canadian Liquids Pipelines business and certain Canadian renewable energy assets to EIPLP in which the Fund has an indirect interest, 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.

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.*

RELATED PARTY TRANSACTIONS

Other than the drop down transactions between Enbridge and its sponsored vehicles, including the Canadian Restructuring Plan and the transactions under the United States Sponsored Vehicle strategy, 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, 2016 (2015 - $7 million; 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, 2016 were $357 million (2015 - $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, 2016, expenses related to the lease arrangement totalled $287 million (2015 - $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 $98 million (2015 - $228 million; 2014 - $315 million) from several joint venture affiliates during the year ended December 31, 2016.

Natural gas sales of $49 million (2015 - $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, 2016.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

Amounts receivable from affiliates include a series of loans to Vector and other affiliates totalling $130 million and $140 million, respectively (2015 - $149 million and $3 million, 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 would purchase on a monthly basis certain trade and accrued receivables of such subsidiaries through December 2016. The Receivables Agreement was amended in June 2016 to extend the termination date that provides for purchases to occur on a monthly basis through to December 2019 provided accumulated purchases net of collections do not exceed US$450 million at any one point. 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 via execution of floating to fixed interest rate swaps with an average swap rate of 2.4%.

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 via execution of floating to fixed interest rate swaps with an average swap rate of 3.7%.

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 CONSOLIDATED STATEMENTS OF 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,	**2016**	2015	2014
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(19)**	77	8
Interest rate contracts	**(90)**	(275)	(1,086)
Commodity contracts	**14**	9	50
Other contracts	**39**	(47)	13
Net investment hedges			
Foreign exchange contracts	**22**	(248)	(113)
	(34)	(484)	(1,128)
Amount of (gains)/loss reclassified from accumulated other comprehensive income (AOCI) to earnings *(effective portion)*			
Foreign exchange contracts[1]	**2**	9	8
Interest rate contracts[2]	**145**	128	101
Commodity contracts[3]	**(12)**	(46)	4
Other contracts[4]	**(29)**	28	(7)
	106	119	106
De-designation of qualifying hedges in connection with the Canadian Restructuring Plan			
Interest rate contracts[2]	**-**	338	-
	-	338	-
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	**61**	21	216
Commodity contracts[3]	**-**	5	(6)
	61	26	210
Amount of gains/(loss) from non-qualifying derivatives included in earnings			
Foreign exchange contracts[1]	**935**	(2,187)	(936)
Interest rate contracts[2]	**73**	(363)	4
Commodity contracts[3]	**(508)**	199	1,031
Other contracts[4]	**9**	(22)	7
	509	(2,373)	106

1 Reported within Transportation and other services revenues and Other income/(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.

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 and maintains substantial capacity under its committed bank lines of credit, as discussed under *Liquidity and Capital Resources*, to address any contingencies. 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 also 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. The Company is in compliance with all the terms and conditions of its committed credit facilities as at December 31, 2016. 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 through credit exposure limits and contractual requirements, netting arrangements and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

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

Economic Regulation, Permits and Approvals

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

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, such as the Merger Transaction and the Company's L3R Program. 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 with respect to projects could result in cost escalations, construction delays and in-service delays which also negatively impact the Company's operations.

The FERC continues to intensify its oversight of financial reporting, risk standards and affiliate rules, and in 2014, the Pipeline and Hazardous Materials Safety Administration 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.

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.

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. The Major Projects Group 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 that 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 the Major Projects Group to engage in open dialogue with government agencies, regulators, land owners, Indigenous peoples and special interest groups to identify and develop appropriate responses to their concerns regarding the Company's projects.

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 the Bakken Pipeline System. 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 Policy and Indigenous Peoples Policy). For further discussion on this strategy, refer to *Corporate Vision and Strategy – Strategy – Maintain the Foundation – Maintain the Company's Social License to Operate.*

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 Indigenous Peoples 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.***

Transformation Projects

Transformation projects risk is the risk that a large change management initiative carried out by the Company will fail to fully deliver anticipated results because of a failure by the Company to fully address risks associated with change delivery and implementation. This could result in negative financial, operational and reputational impacts to the Company. Such large scale change management initiatives include the Merger Transaction and Enbridge's Building Our Energy Future initiative. With respect to the Merger Transaction, Enbridge and Spectra Energy have established a joint integration planning team that is laying the foundation for the efficient integration of the two companies once the Merger Transaction closes and to help ensure that anticipated operating synergies are achieved. For further discussion on the Merger Transaction, refer to *Merger Agreement with Spectra Energy.* In 2016, Enbridge also launched the Building Our Energy Future initiative, an enterprise-wide transformation program that is intended to drive out focused improvements across the enterprise to ensure an effective and efficient organization that will better support the execution of key strategies, such as the above noted Enbridge and Spectra Energy integration. To mitigate its transformation projects risk associated with the Building Our Energy Future initiative, Enbridge established the Results Delivery Office to manage the integrated plan and roadmap of initiatives, execute the transformation process, provide coaching and support to impacted teams in the areas of results delivery, tracking progress and identification of new risks and establishment of appropriate mitigation steps to address those risks.

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 such as the Merger Transaction, may involve significant integration risk as discussed above under *Transformation Projects* and under *Merger Agreement with Spectra Energy*.

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 using consistent due diligence processes, including a thorough review of the asset quality, systems and projected financial performance of the assets being assessed.

Environmental and Safety Risks

Public, Worker and Contractor Safety

Several of the Company's pipelines and distribution systems and related assets are operated in close proximity 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 below 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.

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 reducing 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, regular inspections and monitoring of facilities, as well as 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 excluding costs for fines and penalties. In the unlikely event that 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 and associated entities.

Natural Disaster Incident Risk

Enbridge is exposed to the risk of natural disaster incidents across many of its businesses. Natural disaster events include floods, earthquakes, droughts, wildfires, lightning strikes, wind storms, ice storms, hail storms, tornadoes and mudslides. Recent wildfires in Alberta and their adverse consequences for oil sands operations demonstrate the potential nature and extent of natural disaster incident risk for Enbridge.

Across various businesses, risk treatment measures include construction techniques to limit exposure to natural disaster risk, emergency preparedness plans, business continuity plans, emergency response exercises and insurance in high consequence locations. The Company has made considerable investments in emergency response equipment, training, and additional resources. Insurance coverage also provides protection from loss or damage to Enbridge assets resulting from most natural disaster events.

Information Technology Security or Systems Incident

The Company’s infrastructure, applications and data continue to become 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, threat detection and incident response through a security operations centre. The Company’s security strategy also includes continuing to improve overall intelligence levels related to cyber threat by partnering with a number of external law enforcement agencies and other organizations within its industry.

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, is a key mitigation as the project provides significant diversification of gas supply to EGD’s distribution network and will further reduce the likelihood of a service interruption incident.

Business Environment Risks

Indigenous Peoples Relations

Canadian judicial decisions have recognized that Indigenous peoples’ 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 Indigenous peoples when its decisions or actions may adversely affect Indigenous peoples’ 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 Indigenous peoples’ 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 Indigenous Peoples Policy. This policy promotes the achievement of participative and mutually beneficial relationships with Indigenous peoples affected by the Company’s projects and operations. Specifically, the policy sets out principles governing the Company's relationships with Indigenous peoples and makes commitments to work with Indigenous peoples 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 Indigenous peoples' 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, or otherwise part of, this MD&A.***

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, 2016 of $64,284 million (2015 - $64,434 million), or 75% of total assets, is provided following two primary methods. 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 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.

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 Alberta Energy Regulator, the EUB 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, 2016, the Company's significant regulatory assets totalled $1,865 million (2015 - $1,782 million) and significant regulatory liabilities totalled $844 million (2015 - $869 million).

POSTRETIREMENT BENEFITS

The Company maintains pension plans, which provide defined benefit and/or defined contribution pension benefits and other postretirement benefits (OPEB) to eligible retirees. Pension costs and obligations for the defined benefit pension plans 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 level, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. 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. These assumptions 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 actual return on plan assets exceeded the expectation by $19 million for the year ended December 31, 2016 (2015 - $62 million shortfall) as disclosed in Note 26, Retirement and Postretirement Benefits, to the 2016 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, 2016 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	241	28	24	2
Decrease in expected return on assets	-	11	-	1
Decrease in rate of salary increase	(52)	(12)	-	-

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 2016 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 NEW STANDARDS

Classification of Deferred Taxes on the Statements of Financial Position

Effective January 1, 2016, the Company elected to early adopt Accounting Standards Update (ASU) 2015-17 and applied the standard on a prospective basis. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Consolidated Statements of Financial Position. The adoption of the pronouncement did not have a material impact on the Company’s consolidated financial statements.

Simplifying the Accounting for Measurement-Period Adjustments in Business Combinations

Effective January 1, 2016, the Company adopted ASU 2015-16 on a prospective basis. 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 adoption of the pronouncement did not have a material impact on the Company’s consolidated financial statements.

Measurement Date of Defined Benefit Obligation and Plan Assets

Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis. The revised criteria simplify the fair value measurement of defined benefit plan assets and obligations. The adoption of the pronouncement did not have a material impact on the Company’s consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs

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 and a corresponding decrease in Long-term debt of $149 million. 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. ASU 2015-15 was adopted in conjunction with the above standard and did not have a material impact on the Company’s consolidated financial statements. ASU 2015-15 clarifies 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.

Amendments to the Consolidation Analysis

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, however, material disclosures for VIEs have been provided, as necessary.

Hybrid Financial Instruments Issued in the Form of a Share

Effective January 1, 2016, the Company adopted ASU 2014-16 on a modified retrospective basis. The revised criteria 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. The adoption of the pronouncement did not have a material impact on the Company’s consolidated financial statements.

Development Stage Entities

Effective January 1, 2016, the Company adopted ASU 2014-10 on a retrospective basis. The new standard amends the consolidation guidance to eliminate the development stage entity relief when applying the VIE model and evaluating the sufficiency of equity at risk. The adoption of the pronouncement did not have a material impact on the Company’s consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Clarifying the Definition of a Business in an Acquisition

ASU 2017-01 was issued in January 2017 with the intent of clarifying the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a prospective basis.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows

ASU 2016-18 was issued in November 2016 with the intent to add or clarify guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the cash flow statement. The amendments require that changes in restricted cash and restricted cash equivalents should be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. 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 on a retrospective basis.

Accounting for Intra-Entity Asset Transfers

ASU 2016-16 was issued in October 2016 with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a modified retrospective basis, with early adoption permitted. Effective January 1, 2017, the Company elected to early adopt ASU 2016-16. The adoption of the pronouncement is not anticipated to have a material impact on the Company‘s consolidated financial statements.

Simplifying Cash Flow Classification

ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statements of Cash Flows. The new guidance addresses eight specific presentation issues. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a retrospective basis.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The amendment adds a new impairment model, known as the current expected credit loss model that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2019.

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 Consolidated Statements of Cash Flows. The accounting update is effective for annual and interim periods beginning on or after December 15, 2016 and is to be applied on a prospective or retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company’s consolidated financial statements.

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.

Revenue from Contracts with Customers
ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company is currently assessing which transition method to use.

The Company has reviewed a sample of its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on the Company's initial assessment, the application of the standard may result in a change in presentation in the Gas Distribution business related to payments to customers under the earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments would be reflected as a reduction of revenue. Additionally, estimates of variable consideration which will be required under the new standard for certain Liquids Pipelines, Gas Pipelines and Processing and Green Power and Transmission revenue contracts as well as the allocation of the transaction price for certain Liquids Pipelines revenue contracts, may result in changes to the pattern or timing of revenue recognition for those contracts. While the Company has not yet completed the assessment, the Company's preliminary view is that it does not expect these changes will have a material impact on revenue or earnings (loss). The Company is also developing processes to generate the disclosures required under the new standard.

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, 2016, 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 Securities and Exchange

Commission (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, 2016, 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, 2016.

During the year ended December 31, 2016, 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, 2016 has been audited by PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company.

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2016

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Inc.

Financial Reporting

Management of Enbridge Inc. (the Company) is responsible for the accompanying consolidated financial statements and all related financial information contained in the annual report, including Management's Discussion and Analysis. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles 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, 2016, 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, 2016.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, have conducted an audit of the 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 consolidated financial statements.

“signed”

Al Monaco
President & Chief Executive Officer

“signed”

John K. Whelen
Executive Vice President &
Chief Financial Officer

February 17, 2017

Independent Auditor's Report

To the Shareholders of Enbridge Inc.

We have completed integrated audits of Enbridge Inc.'s 2016, 2015 and 2014 consolidated financial statements and its internal control over financial reporting as at December 31, 2016. Our opinions, based on our audits are presented below.

Report on the consolidated financial statements
We have audited the accompanying consolidated financial statements of Enbridge Inc., which comprise the consolidated statements of financial position as at December 31, 2016 and December 31, 2015 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2016, 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 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 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 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 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 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 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 consolidated financial statements.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Inc. as at December 31 2016 and December 31, 2015 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

Report on internal control over financial reporting
We have also audited Enbridge Inc.'s internal control over financial reporting as at December 31, 2016, 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, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta
February 17, 2017

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2016	2015	2014
(millions of Canadian dollars, except per share amounts)			
Revenues			
Commodity sales	**22,816**	23,842	28,281
Gas distribution sales	**2,486**	3,096	2,853
Transportation and other services	**9,258**	6,856	6,507
	34,560	33,794	37,641
Expenses			
Commodity costs	**22,409**	22,949	27,504
Gas distribution costs	**1,596**	2,292	1,979
Operating and administrative	**4,360**	4,152	3,281
Depreciation and amortization	**2,240**	2,024	1,577
Environmental costs, net of recoveries	**(2)**	(21)	100
Impairment of property, plant and equipment *(Note 9)*	**1,376**	96	-
Goodwill impairment *(Note 15)*	**-**	440	-
	31,979	31,932	34,441
	2,581	1,862	3,200
Income from equity investments *(Note 11)*	**428**	475	368
Other income/(expense) *(Note 27)*	**1,032**	(702)	(266)
Interest expense *(Note 17)*	**(1,590)**	(1,624)	(1,129)
	2,451	11	2,173
Income taxes *(Note 25)*	**(142)**	(170)	(611)
Earnings/(loss) from continuing operations	**2,309**	(159)	1,562
Discontinued Operations			
Earnings from discontinued operations before income taxes	**-**	-	73
Income taxes from discontinued operations	**-**	-	(27)
Earnings from discontinued operations	**-**	-	46
Earnings/(loss)	**2,309**	(159)	1,608
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(240)**	410	(203)
Earnings attributable to Enbridge Inc.	**2,069**	251	1,405
Preference share dividends	**(293)**	(288)	(251)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**1,776**	(37)	1,154
Earnings/(loss) attributable to Enbridge Inc. common shareholders			
Earnings/(loss) from continuing operations	**1,776**	(37)	1,108
Earnings from discontinued operations, net of tax	**-**	-	46
	1,776	(37)	1,154
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders			
Continuing operations	**1.95**	(0.04)	1.34
Discontinued operations	**-**	-	0.05
	1.95	(0.04)	1.39
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders			
Continuing operations	**1.93**	(0.04)	1.32
Discontinued operations	**-**	-	0.05
	1.93	(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,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings/(loss)	**2,309**	(159)	1,608
Other comprehensive income/(loss), net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**(138)**	198	(833)
Change in unrealized gains/(loss) on net investment hedges	**166**	(903)	(270)
Other comprehensive income from equity investees	**-**	30	10
Reclassification to earnings of realized cash flow hedges	**98**	(191)	76
Reclassification to earnings of unrealized cash flow hedges	**18**	(121)	158
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**17**	21	15
Actuarial gains/(loss) on pension plans and other postretirement benefits	**(34)**	51	(191)
Change in foreign currency translation adjustment	**(712)**	3,347	1,238
Reclassification to earnings of derecognized cash flow hedges	**-**	(247)	-
Other comprehensive income/(loss), net of tax	**(585)**	2,185	203
Comprehensive income	**1,724**	2,026	1,811
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(229)**	292	(242)
Comprehensive income attributable to Enbridge Inc.	**1,495**	2,318	1,569
Preference share dividends	**(293)**	(288)	(251)
Comprehensive income attributable to Enbridge Inc. common shareholders	**1,202**	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,	**2016**	2015	2014
(millions of Canadian dollars, except per share amounts)			
Preference shares *(Note 21)*			
Balance at beginning of year	**6,515**	6,515	5,141
Preference shares issued	**740**	-	1,374
Balance at end of year	**7,255**	6,515	6,515
Common shares *(Note 21)*			
Balance at beginning of year	**7,391**	6,669	5,744
Common shares issued	**2,241**	-	446
Dividend reinvestment and share purchase plan	**795**	646	428
Shares issued on exercise of stock options	**65**	76	51
Balance at end of year	**10,492**	7,391	6,669
Additional paid-in capital			
Balance at beginning of year	**3,301**	2,549	746
Stock-based compensation	**41**	35	31
Options exercised	**(24)**	(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)*	**4**	355	-
Dilution gain on Enbridge Income Fund equity investment *(Note 20)*	**73**	132	-
Dilution gain/(loss) on Enbridge Income Fund indirect equity investment *(Note 20)*	**4**	(5)	-
Dilution gains and other	**-**	36	5
Balance at end of year	**3,399**	3,301	2,549
Retained earnings/(deficit)			
Balance at beginning of year	**142**	1,571	2,550
Earnings attributable to Enbridge Inc.	**2,069**	251	1,405
Preference share dividends	**(293)**	(288)	(251)
Common share dividends declared	**(1,945)**	(1,596)	(1,177)
Dividends paid to reciprocal shareholder	**26**	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)*	**(686)**	(359)	(973)
Adjustment relating to equity method investment	**(29)**	-	-
Balance at end of year	**(716)**	142	1,571
Accumulated other comprehensive income/(loss) *(Note 23)*			
Balance at beginning of year	**1,632**	(435)	(599)
Other comprehensive income/(loss) attributable to Enbridge Inc. common shareholders	**(574)**	2,067	164
Balance at end of year	**1,058**	1,632	(435)
Reciprocal shareholding			
Balance at beginning of year	**(83)**	(83)	(86)
Issuance of treasury stock	**(19)**	-	3
Balance at end of year	**(102)**	(83)	(83)
Total Enbridge Inc. shareholders' equity	**21,386**	18,898	16,786
Noncontrolling interests			
Balance at beginning of year	**1,300**	2,015	4,014
Earnings/(loss) attributable to noncontrolling interests	**(28)**	(407)	214
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**4**	161	(192)
Change in foreign currency translation adjustment	**(44)**	273	146
Reclassification to earnings of realized cash flow hedges	**33**	(236)	18
Reclassification to earnings of unrealized cash flow hedges	**7**	(83)	77
	-	115	49
Comprehensive income/(loss) attributable to noncontrolling interests	**(28)**	(292)	263
Distributions	**(720)**	(680)	(535)
Contributions	**28**	615	212
Drop down of interest to Enbridge Energy Partners, L.P. *(Note 20)*	**-**	(304)	-
Enbridge Energy Partners, L.P. equity restructuring	**-**	-	(2,330)
Drop down of interest to Midcoast Energy Partners, L.P.	**-**	-	39
Dilution loss	**-**	(53)	-
Acquisitions - Magic Valley and Wildcat wind farms *(Note 6)*	**-**	-	351
Other	**(3)**	(1)	1
Balance at end of year	**577**	1,300	2,015
Total equity	**21,963**	20,198	18,801
Dividends paid per common share	**2.12**	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,	2016	2015	2014
(millions of Canadian dollars)			
Operating activities			
Earnings/(loss)	**2,309**	(159)	1,608
Earnings from discontinued operations	**-**	-	(46)
Depreciation and amortization	**2,240**	2,024	1,577
Deferred income taxes *(Note 25)*	**43**	7	587
Changes in unrealized (gains)/loss on derivative instruments, net	**(509)**	2,373	(96)
Cash distributions in excess of equity earnings	**171**	244	196
Impairment	**1,620**	536	18
Gains on dispositions *(Note 27)*	**(848)**	(94)	(38)
Hedge ineffectiveness	**61**	(20)	210
Inventory revaluation allowance	**245**	410	174
Unrealized (gains)/loss on intercompany loan	**43**	(131)	(16)
Other	**198**	69	131
Changes in environmental liabilities, net of recoveries	**(4)**	(43)	(78)
Changes in operating assets and liabilities *(Note 29)*	**(358)**	(645)	(1,699)
Cash provided by continuing operations	**5,211**	4,571	2,528
Cash provided by discontinued operations	**-**	-	19
	5,211	4,571	2,547
Investing activities			
Additions to property, plant and equipment	**(5,128)**	(7,273)	(10,524)
Joint venture financing	**(1)**	-	-
Long-term investments	**(467)**	(622)	(854)
Restricted long-term investments	**(46)**	(49)	-
Additions to intangible assets	**(127)**	(101)	(208)
Acquisitions	**(644)**	(106)	(394)
Proceeds from dispositions	**1,379**	146	85
Affiliate loans, net	**(118)**	59	13
Changes in restricted cash	**(40)**	13	(13)
Cash used in continuing operations	**(5,192)**	(7,933)	(11,895)
Cash provided by discontinued operations	**-**	-	4
	(5,192)	(7,933)	(11,891)
Financing activities			
Net change in bank indebtedness and short-term borrowings	**14**	(588)	734
Net change in commercial paper and credit facility draws	**(2,297)**	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	**4,080**	3,767	5,414
Debenture and term note repayments	**(1,946)**	(1,023)	(1,348)
Contributions from noncontrolling interests	**28**	615	212
Distributions to noncontrolling interests	**(720)**	(680)	(535)
Contributions from redeemable noncontrolling interests	**591**	670	323
Distributions to redeemable noncontrolling interests	**(202)**	(114)	(79)
Preference shares issued	**737**	-	1,365
Common shares issued	**2,260**	57	478
Preference share dividends	**(293)**	(288)	(245)
Common share dividends	**(1,150)**	(950)	(749)
	1,102	2,973	9,770
Effect of translation of foreign denominated cash and cash equivalents	**(19)**	143	59
Increase/(decrease) in cash and cash equivalents	**1,102**	(246)	485
Cash and cash equivalents at beginning of year - continuing operations	**1,015**	1,261	756
Cash and cash equivalents at beginning of year - discontinued operations	**-**	-	20
Cash and cash equivalents at end of year	**2,117**	1,015	1,261
Cash and cash equivalents - discontinued operations	**-**	-	-
Cash and cash equivalents - continuing operations	**2,117**	1,015	1,261
Supplementary cash flow information			
Income taxes paid	**194**	80	9
Interest paid	**1,820**	1,835	1,435

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

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2016**	2015
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**2,117**	1,015
Restricted cash	**68**	34
Accounts receivable and other *(Note 7)*	**4,978**	5,430
Accounts receivable from affiliates	**14**	7
Inventory *(Note 8)*	**1,233**	1,111
	8,410	7,597
Property, plant and equipment, net *(Note 9)*	**64,284**	64,434
Long-term investments *(Note 11)*	**6,836**	7,008
Restricted long-term investments *(Note 12)*	**90**	49
Deferred amounts and other assets *(Note 13)*	**3,113**	3,160
Intangible assets, net *(Note 14)*	**1,573**	1,348
Goodwill *(Note 15)*	**78**	80
Deferred income taxes *(Note 25)*	**1,170**	839
Assets held for sale *(Note 6)*	**278**	-
	85,832	84,515
Liabilities and equity		
Current liabilities		
Bank indebtedness	**623**	361
Short-term borrowings *(Note 17)*	**351**	599
Accounts payable and other *(Note 16)*	**7,295**	7,351
Accounts payable to affiliates	**122**	48
Interest payable	**333**	324
Environmental liabilities	**142**	141
Current maturities of long-term debt *(Note 17)*	**4,100**	1,990
	12,966	10,814
Long-term debt *(Note 17)*	**36,494**	39,391
Other long-term liabilities *(Note 18)*	**4,981**	6,056
Deferred income taxes *(Note 25)*	**6,036**	5,915
	60,477	62,176
Commitments and contingencies *(Note 31)*		
Redeemable noncontrolling interests *(Note 20)*	**3,392**	2,141
Equity		
Share capital *(Note 21)*		
Preference shares	**7,255**	6,515
Common shares (943 and 868 outstanding at December 31, 2016 and December 31, 2015, respectively)	**10,492**	7,391
Additional paid-in capital	**3,399**	3,301
Retained earnings/(deficit)	**(716)**	142
Accumulated other comprehensive income *(Note 23)*	**1,058**	1,632
Reciprocal shareholding	**(102)**	(83)
Total Enbridge Inc. shareholders' equity	**21,386**	18,898
Noncontrolling interests *(Note 20)*	**577**	1,300
	21,963	20,198
	85,832	84,515

Variable Interest Entities (Note 10)
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 reporting 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 Alliance Pipeline, 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, Indiana and West Virginia. The Company also has assets under development located in Europe.

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 various pipeline systems.

ELIMINATIONS AND OTHER
In addition to the segments noted above, 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.

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.

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. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity. 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. 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 entity that could potentially be significant to the VIE. Where the Company concludes it is the primary beneficiary of a VIE, the Company will consolidate the accounts of that entity. The Company assesses all variable interests 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 reconsideration of whether an entity is a VIE occurs when there are certain changes in the facts and circumstances related to a VIE. The Company assesses the primary beneficiary determination for a VIE on an ongoing basis, as there are changes in the facts and circumstances related to a VIE. 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, customer relationships and 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. Customer relationships represent the underlying relationship from long term agreements with customers that are capitalized upon acquisition. 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.

Effective January 1, 2016, the Company refined the method to estimate current service cost and interest cost for pension and other postretirement benefits. Previously, these were estimated utilizing a single weighted-average discount rate derived from the yield curve used to measure the defined benefit obligation at the beginning of the year. Under the refined method, different discount rates are derived from the same yield curve, reflecting the different timing of benefit payments for past service (the defined benefit obligation) and future service (the current service cost). Differentiating in this way represents a refinement in the basis of estimation applied in prior periods. This change does not affect the measurement of the total defined benefit obligation recorded on the Consolidated Statements of Financial Position as at December 31, 2016 or any other period. The refinement compared to the previous method resulted in a decrease in the current service cost and interest components with an equal offset to actuarial gains (losses) with no net impact on the total benefit obligation. The refinement did not have a material impact on the Consolidated Statements of Earnings for the year ended December 31, 2016. This change was accounted for prospectively as a change in accounting estimate.

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.

An estimated loss for commitments and contingencies is 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

Classification of Deferred Taxes on the Statements of Financial Position

Effective January 1, 2016, the Company elected to early adopt Accounting Standards Update (ASU) 2015-17 and applied the standard on a prospective basis. The amendments require that deferred tax liabilities and assets be classified as noncurrent in the Consolidated Statements of Financial Position. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Simplifying the Accounting for Measurement-Period Adjustments in Business Combinations

Effective January 1, 2016, the Company adopted ASU 2015-16 on a prospective basis. 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 adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Measurement Date of Defined Benefit Obligation and Plan Assets

Effective January 1, 2016, the Company adopted ASU 2015-04 on a prospective basis. The revised criteria simplify the fair value measurement of defined benefit plan assets and obligations. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Simplifying the Presentation of Debt Issuance Costs

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 and a corresponding decrease in Long-term debt of $149 million. 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. ASU 2015-15 was adopted in conjunction with the above standard and did not have a material impact on the Company's consolidated financial statements. ASU 2015-15 clarifies 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.

Amendments to the Consolidation Analysis

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, however, material disclosures for VIEs have been provided, as necessary.

Hybrid Financial Instruments Issued in the Form of a Share

Effective January 1, 2016, the Company adopted ASU 2014-16 on a modified retrospective basis. The revised criteria 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. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

Development Stage Entities

Effective January 1, 2016, the Company adopted ASU 2014-10 on a retrospective basis. The new standard amends the consolidation guidance to eliminate the development stage entity relief when applying the VIE model and evaluating the sufficiency of equity at risk. The adoption of the pronouncement did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Clarifying the Definition of a Business in an Acquisition

ASU 2017-01 was issued in January 2017 with the intent of clarifying the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses. The Company is currently assessing the impact of the new standard on the consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a prospective basis.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows

ASU 2016-18 was issued in November 2016 with the intent to add or clarify guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the cash flow statement. The amendments require that changes in restricted cash and restricted cash equivalents should be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. 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 on a retrospective basis.

Accounting for Intra-Entity Asset Transfers

ASU 2016-16 was issued in October 2016 with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a modified retrospective basis, with early adoption permitted. Effective January 1, 2017, the Company elected to early adopt ASU 2016-16. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Simplifying Cash Flow Classification

ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statements of Cash Flows. The new guidance addresses eight specific presentation issues. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2017 and is to be applied on a retrospective basis.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The amendment adds a new impairment model, known as the current expected credit loss model that is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The Company is currently assessing the impact of the new standard on its consolidated financial statements. The accounting update is effective for annual and interim periods beginning on or after December 15, 2019.

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 Consolidated Statements of Cash Flows. The accounting update is effective for annual and interim periods beginning on or after December 15, 2016 and is to be applied on a prospective or retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

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.

Revenue from Contracts with Customers
ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. The standard is effective January 1, 2018. The new revenue standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. The Company is currently assessing which transition method to use.

The Company has reviewed a sample of its revenue contracts in order to evaluate the effect of the new standard on its revenue recognition practices. Based on the Company's initial assessment, the application of the standard may result in a change in presentation in the Gas Distribution business related to payments to customers under the earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments would be reflected as a reduction of revenue. Additionally, estimates of variable consideration which will be required under the new standard for certain Liquids Pipelines, Gas Pipelines and Processing and Green Power and Transmission revenue contracts as well as the allocation of the transaction price for certain Liquids Pipelines revenue contracts, may result in changes to the pattern or timing of revenue recognition for those contracts. While the Company has not yet completed the assessment, the Company's preliminary view is that it does not expect these changes will have a material impact on revenue or earnings (loss). The Company is also developing processes to generate the disclosures required under the new standard.

4. SEGMENTED INFORMATION

Effective January 1, 2016, the Company revised its reportable segments. Revisions to the segmented information presentation on a retrospective basis 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; and
- 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.

On May 12, 2016, the Company filed amended financial statements for the year ended December 31, 2015 to retrospectively apply the revisions of its reportable segments to the 2015 financial statements of the Company that were previously filed on February 19, 2016.

Segmented information for the years ended December 31, 2016, 2015 and 2014 are as follows:

Year ended December 31, 2016	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**8,176**	**2,976**	**2,877**	**502**	**20,364**	**(335)**	**34,560**
Commodity and gas distribution costs	**(12)**	**(1,653)**	**(2,206)**	**5**	**(20,473)**	**334**	**(24,005)**
Operating and administrative	**(2,910)**	**(553)**	**(447)**	**(173)**	**(63)**	**(214)**	**(4,360)**
Depreciation and amortization	**(1,369)**	**(339)**	**(292)**	**(190)**	**(2)**	**(48)**	**(2,240)**
Environmental costs, net of recoveries	**2**	**-**	**-**	**-**	**-**	**-**	**2**
Impairment of property, plant and equipment	**(1,365)**	**-**	**(11)**	**-**	**-**	**-**	**(1,376)**
	2,522	**431**	**(79)**	**144**	**(174)**	**(263)**	**2,581**
Income/(loss) from equity investments	**194**	**12**	**223**	**2**	**(3)**	**-**	**428**
Other income/(expense)	**841**	**49**	**27**	**8**	**(8)**	**115**	**1,032**
Earnings/(loss) before interest and income taxes	**3,557**	**492**	**171**	**154**	**(185)**	**(148)**	**4,041**
Interest expense							**(1,590)**
Income taxes							**(142)**
Earnings							**2,309**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests							**(240)**
Preference share dividends							**(293)**
Earnings attributable to Enbridge Inc. common shareholders							**1,776**
Additions to property, plant and equipment[1]	**3,957**	**713**	**176**	**251**	**-**	**32**	**5,129**
Total assets	**52,043**	**10,204**	**11,182**	**5,571**	**1,951**	**4,881**	**85,832**

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	(2,769)	(536)	(506)	(143)	(66)	(132)	(4,152)
Depreciation and amortization	(1,227)	(308)	(272)	(186)	1	(32)	(2,024)
Environmental costs, net of recoveries	21	-	-	-	-	-	21
Impairment of property, plant and equipment	(80)	-	(16)	-	-	-	(96)
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

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,	**2016**	2015	2014
(millions of Canadian dollars)			
Canada	**12,470**	11,087	14,963
United States	**22,090**	22,707	22,678
	34,560	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,	**2016**	2015
(millions of Canadian dollars)		
Canada	**32,008**	30,656
United States	**32,276**	33,778
	64,284	64,434

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 by the NEB. The Company also collects and sets aside funds to cover future pipeline abandonment costs for all NEB regulated pipelines as a result of the NEB's regulatory requirements under LMCI (Note 12). Amounts expected to be paid to cover future abandonment costs are recognized as long-term regulatory liabilities. The Company's significant regulated businesses and other 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, 2016 and 2015 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.

EGD's after-tax rate of return on common equity embedded in rates was 9.2% for the year ended December 31, 2016 (2015 - 9.3%) based on a 36% (2015 - 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,	**2016**	2015
(millions of Canadian dollars)		
Regulatory assets/(liabilities)		
Liquids Pipelines		
Deferred income taxes[1]	**1,270**	1,048
Tolling deferrals[2]	**(37)**	(39)
Recoverable income taxes[3]	**51**	54
Pipeline future abandonment costs[4]	**(88)**	(47)
Transportation revenue adjustments[5]	**-**	11
Gas Distribution		
Deferred income taxes[6]	**385**	328
Purchased gas variance[7]	**5**	129
Pension plans and OPEB[8]	**116**	104
Constant dollar net salvage adjustment[9]	**38**	42
Unabsorbed demand cost[10]	**-**	66
Future removal and site restoration reserves[11]	**(606)**	(581)
Site restoration clearance adjustment[12]	**(109)**	(193)
Transaction services deferral[13]	**(4)**	(9)

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.

6 The deferred income tax asset represents the regulatory offset to deferred income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of the temporary differences.

7 Purchased gas variance (PGVA) is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution 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 balance 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, 2016 was $71 million (2015 - $75 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 clearance adjustment. At the end of 2018, any residual balance will be cleared in a post 2018 true up.
10 The unabsorbed demand cost deferral account represents the actual cost consequences of unutilized transportation capacity contracted by Enbridge Gas Distribution to meet requirements resulting from its Peak Gas Design Day Criteria.
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, that was determined by the OEB, of previously collected costs for future removal and site restoration that is now considered to be in excess of future requirements and will be refunded to customers over the customized IR term. This was a result of the OEB's approval of the adoption of a new approach for determining net negative salvage percentages. The new approach resulted in lower depreciation rates and lower future removal and site restoration reserves.
13 The transaction services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount 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, 2016, cumulative costs relating to this consulting contract of $181 million (2015 - $179 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. ACQUISITION AND DISPOSITIONS

ACQUISITIONS

Spectra Energy Corp

On September 6, 2016 Enbridge and Spectra Energy Corp (Spectra Energy) announced that they had entered into a definitive merger agreement under which Enbridge and Spectra Energy would combine in a stock-for-stock merger transaction (the Merger Transaction). The Merger Transaction was unanimously approved by the Boards of Directors and shareholders of both companies. Shareholders' approval for both companies was received in December 2016 and the Merger Transaction is expected to close in the first quarter of 2017, subject to certain regulatory approvals and other customary conditions.

Under the terms of the Merger Transaction, Spectra Energy shareholders will receive 0.984 shares of the combined company for each share of Spectra Energy common stock they own. Upon completion of the Merger Transaction, Enbridge shareholders are expected to own approximately 57% of the combined company and Spectra Energy shareholders are expected to own approximately 43%. The combined company will be called Enbridge Inc.

Tupper Main and Tupper West
On April 1, 2016, Enbridge acquired the Tupper Main and Tupper West gas plants and associated pipelines (the Tupper Plants) located in northeastern British Columbia for cash consideration of $539 million. The purchase price for the Tupper Plants was equal to the fair value of identifiable net assets acquired and accordingly, the Company did not recognize any goodwill as part of the acquisition. Transaction costs incurred by the Company totalled approximately $1 million and are included in Operating and administrative expense within the Consolidated Statements of Earnings. The Tupper Plants are included within the Gas Pipelines and Processing segment.

Since the closing date through December 31, 2016, the Tupper Plants have generated approximately $33 million in revenues and $22 million in earnings before interest and income taxes. If the acquisition had closed on January 1, 2016, the Consolidated Statements of Earnings for the years ended December 31, 2016, would have shown revenues of $44 million and earnings before interest and income taxes of $28 million, respectively.

The final purchase price allocation was as follows:

April 1,	2016
(millions of Canadian dollars)	
Fair value of net assets acquired:	
Property, plant and equipment	288
Intangible assets	251
	539
Purchase price:	
Cash	539

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, 2015, changes to revenues and earnings for the years ended December 31, 2016 and 2015 would have been nominal.

The final purchase price allocation was as follows:

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 was $3 million (US$2 million). During the first quarter of 2016, and upon subsequent reassessments, MEP determined, based on current and forecasted volumes, that it is remote that MEP will be obligated to make any payments at the expiration of the five-year period. Consequently, the liability was reversed and a $4 million (US$3 million) gain was recognized as a reduction to "Operating and administrative" expense, which is reflected in the consolidated statements of income for the year ended December 31, 2016.

Magic Valley and Wildcat Wind Farms

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, 2013, 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, and proforma consolidated revenues and earnings for the year ended December 31, 2013 would have increased by $44 million (US$43 million) and decreased by $2 million (US$2 million), respectively.

The final purchase price allocation was a follows:

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]	(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

Chapman Ranch Wind Project

On September 9, 2016, the Company acquired a 100% interest in the 249 megawatt (MW) Chapman Ranch Wind Project (Chapman Ranch) located in Texas for cash consideration of $65 million (US$50 million), of which $62 million (US$48 million) was allocated to Property, plant and equipment and the balance allocated to Intangible assets. On November 2, 2016, the Company invested a further $40 million (US$30 million) in Chapman Ranch, of which $23 million (US$17 million) was related to Property, plant and equipment and the balance related to Intangible assets. There would have been no effect on earnings if the transaction had occurred on January 1, 2016 as the project is under construction and has not generated revenues to date. Chapman Ranch is included within the Green Power and Transmission segment.

Other
In November 2015, the Company acquired a 100% interest in the 103 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 was placed into 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.

ASSETS HELD FOR SALE
In December 2016, the Company entered into an agreement to sell the Ozark Pipeline assets to a subsidiary of MPLX LP for cash proceeds of approximately $294 million (US$219 million), including $13 million (US$10 million) in reimbursable capital costs up to the closing date of the transaction. Subject to certain pre-closing conditions, the transaction is expected to close by the end of the first quarter of 2017. The Ozark Pipeline is included within the Company's Liquids Pipelines segment.

As at December 31, 2016, the assets of Ozark Pipeline were classified as held for sale and were measured at the lower of their carrying value or fair value less costs to sell, which did not result in a fair value adjustment. Included within Assets held for sale on the Consolidated Statements of Financial Position was $278 million (US$207 million) related to Property, plant and equipment.

DISPOSITIONS
South Prairie Region
On December 1, 2016, the Company completed the sale of the South Prairie Region assets to an unrelated party for cash proceeds of $1.08 billion. A gain on sale of $850 million before tax was recognized in Other income/(expense) on the Consolidated Statements of Earnings. The South Prairie Region assets were included within the Company's Liquids Pipelines segment. For the year ended December 31, 2016, pre-tax earnings for the South Prairie Region assets were $41 million.

OTHER DISPOSITIONS
In December 2016, the Company sold other miscellaneous non-core assets for cash proceeds of $286 million.

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 income/(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 income/(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 income/(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.

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 income/(expense) on the Consolidated Statements of Earnings.

7. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2016**	2015
(millions of Canadian dollars)		
Unbilled revenues	**2,886**	2,476
Trade receivables	**974**	1,079
Taxes receivable	**222**	175
Regulatory assets	**66**	216
Short-term portion of derivative assets *(Note 24)*	**353**	791
Prepaid expenses and deposits	**168**	181
Current deferred income taxes *(Note 25)*	**-**	367
Dividends receivable	**26**	26
Rebillable receivables	**63**	-
Agent billing and collection receivable	**35**	39
Other	**231**	125
Allowance for doubtful accounts	**(46)**	(45)
	4,978	5,430

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain EEP 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 was amended in June 2016 to extend the termination date that provides for purchases to occur on a monthly basis through to December 2019, 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$355 million ($477 million) and US$317 million ($439 million) as at December 31, 2016 and December 31, 2015, respectively.

8. INVENTORY

December 31,	**2016**	2015
(millions of Canadian dollars)		
Natural gas	**594**	627
Crude oil	**634**	477
Other commodities	**5**	7
	1,233	1,111

9. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2016**	2015
(millions of Canadian dollars)			
Liquids Pipelines			
Pipeline	2.7%	**30,809**	31,092
Pumping equipment, buildings, tanks and other	3.0%	**15,215**	14,319
Land and right-of-way	2.4%	**1,218**	1,221
Under construction	-	**5,419**	6,002
		52,661	52,634
Accumulated depreciation		**(8,996)**	(8,233)
		43,665	44,401
Gas Distribution			
Gas mains, services and other	3.1%	**10,022**	8,819
Land and right-of-way	1.0%	**133**	85
Under construction	-	**144**	902
		10,299	9,806
Accumulated depreciation		**(2,524)**	(2,379)
		7,775	7,427
Gas Pipelines and Processing			
Pipeline	3.0%	**3,665**	3,557
Compressors, meters and other operating equipment	2.4%	**4,014**	3,864
Processing and treating plants	2.4%	**846**	869
Pumping equipment, buildings, tanks and other	8.4%	**306**	275
Land and right-of-way	2.3%	**673**	680
Under construction	-	**791**	956
		10,295	10,201
Accumulated depreciation		**(2,167)**	(2,003)
		8,128	8,198
Green Power and Transmission			
Wind turbines, solar panels and other	4.1%	**4,259**	4,311
Power transmission	2.2%	**378**	387
Land and right-of-way	1.9%	**43**	45
Under construction	-	**612**	51
		5,292	4,794
Accumulated depreciation		**(778)**	(600)
		4,514	4,194
Energy Services			
Pumping equipment and other	4.0%	**33**	34
		33	34
Accumulated depreciation		**(13)**	(13)
		20	21
Eliminations and Other			
Vehicles, office furniture, equipment and other	9.3%	**315**	331
		315	331
Accumulated depreciation		**(133)**	(138)
		182	193
		64,284	64,434

Depreciation expense for the year ended December 31, 2016 was $2,049 million (2015 - $1,852 million 2014 - $1,461 million).

IMPAIRMENT

Northern Gateway Pipeline Project

On November 29, 2016, the Canadian Federal Government directed the NEB to dismiss the Company's Northern Gateway application and the Certificates of Public Convenience and Necessity have been rescinded. In consultation with potential shippers and Aboriginal equity partners, the Company assessed this decision and concluded that the project cannot proceed as envisioned. After taking into consideration the amount recoverable from potential shippers on Northern Gateway, the Company recognized an impairment of $373 million ($272 million after-tax), which is included in Impairment of property, plant and equipment in the Consolidated Statements of Earnings. This impairment loss is based on the full carrying value of the assets, which have an estimated fair value of nil, and is included within the Liquids Pipelines segment.

Sandpiper Project

On September 1, 2016, Enbridge announced that EEP applied for the withdrawal of regulatory applications pending with the Minnesota Public Utilities Commission for the Sandpiper Project (Sandpiper). In connection with this announcement and other factors, the Company evaluated Sandpiper for impairment. As a result, the Company recognized an impairment loss of $992 million ($81 million after-tax attributable to Enbridge) for the year ended December 31, 2016, which is included in Impairment of property, plant and equipment in the Consolidated Statements of Earnings. Sandpiper is included within the Liquids Pipelines segment. The estimated remaining fair value of $71 million of Sandpiper is based on the estimated price that would be received to sell unused pipe, land and other related equipment in its current condition, considering the current market conditions for sale of these assets. The valuation considered a range of potential selling prices from various alternatives that could be used to dispose of these assets. The estimated fair value, with the exception of $3 million in land, has been reclassified into Deferred amounts and other assets in the Consolidated Statements of Financial Position as at December 31, 2016.

Other

For the year ended December 31, 2016, the Company recorded impairment charges of $11 million related to EEP's non-core trucking assets and related facilities, included within the Gas Pipelines and Processing segment.

For the year ended December 31, 2015, 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.

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 Impairment of property, plant and equipment 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

CONSOLIDATED VARIABLE INTEREST ENTITIES

Enbridge Energy Partners, L.P.

EEP is a publicly-traded Delaware limited partnership and is considered a VIE as its limited partners do not have substantive kick-out rights or participating rights. Enbridge, through its wholly-owned subsidiary, Enbridge Energy Company, Inc. (EECI), has the power to direct EEP's activities that have a significant impact on EEP's economic performance. Along with a 35.3% (2015 - 35.7%; 2014 - 33.7%) economic interest held through an indirect common interest and preferred unit interest through EECI, the Company, through its 100% ownership of EECI, is the primary beneficiary of EEP. The public owns the remaining interests in EEP.

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 86.9% (2015 - 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. As at December 31, 2016, the Company's direct common interest in the Fund was 43.2% (2015 - 49.2%; 2014 - 11.9%). Enbridge also serves in the capacity of Manager of ENF and the Fund Group.

Enbridge Commercial Trust
Enbridge has the ability 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.

Enbridge Income Partners LP
EIPLP, formed in 2002, is involved in the generation, transportation and storage of energy through interests in its Liquids Pipelines business, including the Canadian Mainline, the Regional Oil Sands System, a 50.0% interest in the Alliance Pipeline, which transports natural gas, and its renewable and alternative power generation facilities. EIPLP is a partnership between an indirect wholly-owned subsidiary of the Company and ECT. EIPLP is considered a VIE as its limited partners lack substantive kick-out rights and participating rights. Through a majority ownership of EIPLP's General Partner, 100% ownership of Enbridge Management Services Inc. (a service provider for EIPLP), and 54.2% of direct common interest in EIPLP, the Company has the power to direct the activities that most significantly impact EIPLP's economic performance and has the obligation to absorb losses and the right to receive residual returns that are potentially significant to EIPLP, making the Company the primary beneficiary of EIPLP. As at December 31, 2016, the Company's economic interest in EIPLP was 79.1%.

Green Power and Transmission
Through various subsidiaries, Enbridge has majority ownership interest in Magic Valley, Wildcat, Keechi, and New Creek wind farms. These wind farms are considered VIEs as they do not have sufficient equity at risk and are partially financed by tax equity investors. Enbridge is the primary beneficiary of these 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 its obligation to absorb losses.

Other Limited Partnerships
By virtue of a lack of substantive kick-out rights and participating rights, substantially all limited partnerships wholly-owned by Enbridge and/or its subsidiaries are considered VIEs. As these entities are 100% owned and directed by Enbridge with no third parties having the ability to direct any of the significant activities, the Company is considered the primary beneficiary.

The following table includes assets to be used to settle liabilities of Enbridge's consolidated VIEs and liabilities of Enbridge's consolidated VIEs for which creditors do not have recourse to the Company's general credit as the primary beneficiary. These assets and liabilities are included in the Consolidated Statements of Financial Position.

December 31,	**2016**	2015
(millions of Canadian dollars)		
Assets		
Cash and cash equivalents	**486**	362
Restricted cash	**-**	26
Accounts receivable and other	**781**	972
Accounts receivable from affiliates	**3**	29
Inventory	**53**	54
	1,323	1,443
Property, plant and equipment, net	**45,720**	45,882
Long-term investments	**954**	1,005
Restricted long-term investments	**83**	45
Deferred amounts and other assets	**1,949**	1,806
Intangible assets, net	**488**	525
Goodwill	**29**	29
Deferred income taxes	**231**	267
Assets held for sale	**278**	-
	51,055	51,002
Liabilities		
Bank indebtedness	**172**	33
Accounts payable and other	**1,446**	2,077
Accounts payable to affiliates	**105**	92
Interest payable	**204**	202
Environmental liabilities	**140**	139
Current maturities of long-term debt	**342**	760
	2,409	3,303
Long-term debt	**20,176**	19,998
Other long-term liabilities	**1,207**	1,340
Deferred income taxes	**1,753**	1,253
	25,545	25,894
Net assets before noncontrolling interests	**25,510**	25,108

The Company does not have an obligation to provide financial support to any of the consolidated VIEs, with the exception of EIPLP. The Company is required, when called on by Enbridge Income Fund Holdings Inc., to backstop equity funding required by EIPLP to undertake the growth program embedded in the assets it acquired in the Canadian Restructuring Plan.

UNCONSOLIDATED VARIABLE INTEREST ENTITIES

The Company currently holds several equity investments in limited partnerships that are assessed to be VIEs due to limited partners not having substantive kick-out rights or participating rights. Enbridge has determined that it does not have the power to direct the activities of the VIEs that most significantly impact the VIEs’ economic performance. Specifically, the power to direct the activities of a majority of these VIEs is shared amongst the partners. Each partner has representatives that make up an executive committee who makes significant decisions for the VIE and none of the partners may make major decisions unilaterally.

The carrying amount of the Company's interest in VIEs that are unconsolidated and its estimated maximum exposure to loss as at December 31, 2016 and 2015 is presented below.

December 31, 2016	Carrying Amount of Investment in VIE	Enbridge's Maximum Exposure to Loss
(millions of Canadian dollars)		
Vector Pipeline L.P.[4]	**159**	**289**
Aux Sable Liquid Products L.P.[2]	**158**	**223**
Rampion Offshore Wind Limited[3]	**345**	**457**
Eddystone Rail Company, LLC[4]	**19**	**25**
Illinois Extension Pipeline Company, L.L.C.[1]	**759**	**759**
Eolien Maritime France SAS[5]	**58**	**686**
Other[1]	**17**	**17**
	1,515	**2,456**

December 31, 2015	Carrying Amount of Investment in VIE	Enbridge's Maximum Exposure to Loss
(millions of Canadian dollars)		
Vector Pipeline L.P.[4]	159	308
Aux Sable Liquid Products L.P.[1]	175	175
Rampion Offshore Wind Limited[3]	201	403
Eddystone Rail Company, LLC[4]	168	220
Illinois Extension Pipeline Company, L.L.C.[1]	713	713
Other[1]	15	15
	1,431	1,834

1 At December 31, 2016, the maximum exposure to loss for these entities is limited to the Company's equity investment as these companies are in operation and self-sustaining.
2 At December 31, 2016, the maximum exposure to loss includes a guarantee by the Company for its respective share of the VIE's borrowing on a bank credit facility.
3 At December 31, 2016, the maximum exposure to loss includes the portion of the Company's parental guarantee that has been committed in project construction contracts in which the Company would be liable for in the event of default by the VIE.
4 At December 31, 2016 the maximum exposure to loss includes the carrying value of an outstanding loan issued by the Company.
5 At December 31, 2016, the maximum exposure to loss includes the portion of the Company's parental guarantee that has been committed in project construction contracts in which the Company would be liable for in the event of default by the VIE and an outstanding affiliate loan receivable for $136 million held by the Company.

The Company does not have an obligation to and did not provide any additional financial support to the VIEs during the year ended December 31, 2016.

11. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	2016	2015
(millions of Canadian dollars)			
EQUITY INVESTMENTS			
Liquids Pipelines			
Seaway Crude Pipeline System	50.0%	**3,129**	3,251
Southern Access Extension Project	65.0%	**759**	713
Enbridge Rail (Philadelphia) L.L.C.	75.0%	**19**	168
Other	30.0% - 43.9%	**70**	69
Gas Distribution			
Noverco Common Shares	38.9%	**-**	-
Gas Pipelines and Processing			
Texas Express Pipeline	35.0%	**484**	515
Alliance Pipeline	50.0%	**411**	427
Aux Sable	42.7% - 50.0%	**324**	344
Vector Pipeline	60.0%	**159**	159
Offshore - various joint ventures	22.0% - 74.3%	**435**	479
Other	33.3% - 70.0%	**4**	12
Green Power and Transmission			
Rampion offshore wind project[1]	24.9%	**345**	201
Eolien Maritime France SAS[2]	50.0%	**58**	-
Other	18.9% - 50.0%	**100**	109
Eliminations and Other			
Other	19.0% - 42.7%	**15**	12
OTHER LONG-TERM INVESTMENTS			
Gas Distribution			
Noverco Preferred Shares		**355**	359
Green Power and Transmission			
Emerging Technologies and Other		**90**	106
Eliminations and Other			
Other		**79**	84
		6,836	7,008

1 On November 4, 2015, Enbridge acquired a 24.9% equity interest in Rampion Offshore Wind Limited.
2 On May 19, 2016, Enbridge acquired a 50% equity interest in Eolien Maritime France SAS.

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 $859 million (2015 - $885 million) in Goodwill and $687 million (2015 - $568 million) in amortizable assets.

For the year ended December 31, 2016, dividends received from equity investments was $825 million (2015 - $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,	**2016**	2015	2014
(millions of Canadian dollars)			
Revenues	**1,761**	1,557	1,790
Commodity costs	**(385)**	(369)	(661)
Operating and administrative expense	**(545)**	(376)	(444)
Depreciation and amortization	**(293)**	(274)	(232)
Other income/(expense)	**(41)**	4	(1)
Interest expense	**(69)**	(67)	(84)
Earnings before income taxes	**428**	475	368

December 31,	**2016**	2015
(millions of Canadian dollars)		
Current assets	**464**	389
Property, plant and equipment, net	**6,534**	6,602
Deferred amounts and other assets	**47**	40
Intangible assets, net	**118**	64
Goodwill	**862**	885
Current liabilities	**(433)**	(500)
Long-term debt	**(792)**	(854)
Other long-term liabilities	**(488)**	(167)
Net assets	**6,312**	6,459

Alliance Pipeline
Certain assets of the Alliance Pipeline are pledged as collateral to Alliance Pipeline lenders.

Noverco
As at December 31, 2016, Enbridge owned an equity interest in Noverco through ownership of 38.9% (2015 - 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 margin of 4.38%.

As at December 31, 2016, Noverco owned an approximate 3.4% (2015 - 3.6%; 2014 - 3.6%) reciprocal shareholding in common shares of Enbridge. Through secondary offerings, Noverco purchased 1.2 million common shares in February 2016 and sold 1.3 million common shares in 2014. Shares purchased and sold in these transactions were treated as 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 1.3% (2015 - 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 $102 million at December 31, 2016 (2015 - $83 million; 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.

Eddystone Rail Company, LLC
During the year ended December 31, 2016, the Company recorded an investment impairment of $184 million related to Enbridge's 75% joint venture interest in Eddystone Rail Company, LLC (Eddystone Rail), which is held through Enbridge Rail (Philadelphia) L.L.C., a wholly-owned subsidiary. Eddystone Rail is a rail-to-barge transloading facility located in the greater Philadelphia, Pennsylvania area that delivers Bakken and other light sweet crude oil to Philadelphia area refineries. Due to a significant decrease in price spreads between Bakken crude oil and West Africa/Brent crude oil and increased competition in the region, demand for Eddystone Rail services dropped significantly, which led to the

completion of an impairment test. The impairment charge is presented within Income from equity investments on the Consolidated Statements of Earnings. The investment in Eddystone Rail is included within the Liquids Pipelines segment.

The impairment charge was based on the amount by which the carrying value of the asset exceeded fair value, determined using an adjusted net worth approach. The Company'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 Eddystone Rail.

Aux Sable

During the year ended December 31, 2016, Aux Sable recorded an asset impairment charge of $37 million related to certain underutilized assets at Aux Sable US' NGL extraction and fractionation plant.

Eolien Maritime France SAS

Effective May 19, 2016, Enbridge acquired a 50% interest in Eolien Maritime France SAS (EMF), a French offshore wind development company. EMF is co-owned by Enbridge and EDF Energies Nouvelles, a subsidiary of Électricité de France S.A. EMF holds licenses for three large-scale offshore wind farms off the coast of France, which are currently under development. Enbridge's portion of the costs incurred to date is approximately $194 million (€136 million) with $58 million presented in Long-term investments, and $136 million presented in Deferred amounts and other assets.

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 $345 million (£195 million) presented in Long-term investments.

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.

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, 2016, 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 $90 million (2015

- $49 million). As at December 31, 2016, the Company had estimated future abandonment costs of $97 million (2015 - $48 million) related to LMCI.

13. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2016**	2015
(millions of Canadian dollars)		
Regulatory assets	**1,921**	1,661
Long-term portion of derivative assets *(Note 24)*	**151**	373
Affiliate long-term notes receivable	**270**	152
Contractual receivables	**441**	432
Deferred financing costs	**51**	52
Other	**279**	490
	3,113	3,160

As at December 31, 2016, deferred amounts of $150 million (2015 - $141 million) were subject to amortization and are presented net of accumulated amortization of $94 million (2015 - $80 million). Amortization expense for the year ended December 31, 2016 was $20 million (2015 - $18 million; 2014 - $22 million).

14. INTANGIBLE ASSETS

December 31, 2016	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Software	11.8%	**1,388**	**607**	**781**
Natural gas supply opportunities	3.2%	**435**	**127**	**308**
Power purchase agreements	3.2%	**100**	**14**	**86**
Customer relationships	3.0%	**251**	**4**	**247**
Land leases, permits and other	4.8%	**213**	**62**	**151**
		2,387	**814**	**1,573**

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

Total amortization expense for intangible assets was $177 million (2015 - $158 million; 2014 - $106 million) for the year ended December 31, 2016. The Company expects amortization expense for intangible assets for the years ending December 31, 2017 through 2021 of $198 million, $178 million, $159 million, $143 million and $129 million, respectively.

15. GOODWILL

(millions of Canadian dollars)	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
Balance at January 1, 2015	55	-	428	-	-	-	483
Foreign exchange and other	5	-	30	-	2	-	37
Impairment	-	-	(440)	-	-	-	(440)
Balance at December 31, 2015	**60**	**-**	**18**	**-**	**2**	**-**	**80**
Foreign exchange and other	**(1)**	**-**	**(1)**	**-**	**-**	**-**	**(2)**
Balance at December 31, 2016	**59**	**-**	**17**	**-**	**2**	**-**	**78**

IMPAIRMENT
The Company did not recognize any goodwill impairment for the year ended December 31, 2016.

Gas Pipelines And Processing
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.

16. ACCOUNTS PAYABLE AND OTHER

December 31,	**2016**	2015
(millions of Canadian dollars)		
Operating accrued liabilities	**3,487**	3,028
Trade payables	**328**	561
Construction payables	**587**	750
Current derivative liabilities *(Note 24)*	**1,941**	1,945
Contractor holdbacks	**125**	299
Taxes payable	**321**	376
Security deposits	**52**	62
Deferred revenue	**138**	89
Asset retirement obligations *(Note 19)*	**2**	9
Other	**314**	232
	7,295	7,351

17. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2016**	2015
(millions of Canadian dollars)				
Enbridge Inc.				
United States dollar term notes[1]	4.1%	2017-2046	**5,639**	4,221
Medium-term notes	4.2%	2017-2064	**4,998**	5,698
Fixed-to-floating subordinated term notes[2]	6.0%	2077	**1,007**	-
Commercial paper and credit facility draws[3]			**4,672**	5,667
Other[4]			**4**	7
Enbridge (U.S.) Inc.				
Medium-term notes[5]	5.1%	2020	**14**	14
Commercial paper and credit facility draws[6]			**126**	1,665
Enbridge Energy Partners, L.P.				
Senior notes[7]	6.2%	2018-2045	**6,781**	7,404
Junior subordinated notes[8]	8.1%	2067	**537**	554
Commercial paper and credit facility draws[9]			**2,226**	1,988
Enbridge Gas Distribution Inc.				
Medium-term notes	4.4%	2017-2050	**3,904**	3,603
Debentures	9.9%	2024	**85**	85
Commercial paper and credit facility draws			**351**	599
Enbridge Income Fund				
Medium-term notes	4.2%	2017-2044	**2,075**	2,405
Commercial paper and credit facility draws			**225**	-
Enbridge Pipelines (Southern Lights) L.L.C.				
Medium-term notes[10]	4.0%	2040	**1,342**	1,425
Enbridge Pipelines Inc.				
Medium-term notes[11]	4.5%	2018-2046	**4,525**	3,725
Debentures	8.2%	2024	**200**	200
Commercial paper and credit facility draws			**1,032**	1,346
Other			**4**	4
Enbridge Southern Lights LP				
Medium-term notes	4.0%	2040	**323**	336
Midcoast Energy Partners, L.P.				
Senior notes[12]	4.1%	2019-2024	**537**	554
Commercial paper and credit facility draws[13]			**564**	678
Other[14]			**(226)**	(198)
Total debt			**40,945**	41,980
Current maturities			**(4,100)**	(1,990)
Short-term borrowings[15]			**(351)**	(599)
Long-term debt			**36,494**	39,391

1 2016 - US$4,200 million (2015 - US$3,050 million).
2 2016 - US$750 million (2015 - nil).
3 2016 - $3,600 million and US$799 million (2015 - $4,168 million and US$1,084 million).
4 Primarily capital lease obligations.
5 2016 - US$10 million (2015 - US$10 million).
6 2016 - US$94 million (2015 - US$1,203 million).
7 2016 - US$5,050 million (2015 - US$5,350 million).
8 2016 - US$400 million (2015 - US$400 million).
9 2016 - US$1,658 million (2015 - US$1,436 million).
10 2016 - US$1,000 million (2015 - US$1,030 million).
11 Included in medium-term notes is $100 million with a maturity date of 2112.
12 2016 - US$400 million (2015 - US$400 million).
13 2016 - US$420 million (2015 - US$490 million).
14 Primarily debt discount and debt issue costs.
15 Weighted average interest rate - 0.8% (2015 - 0.8%).

For the years ending December 31, 2017 through 2021, debenture, term note and non-revolving credit facility maturities are $4,100 million, $1,172 million, $3,111 million, $2,797 million, $1,917 million respectively, and $21,618 million thereafter. The Company's debentures and term notes bear interest at fixed rates and interest obligations for the years ending December 31, 2017 through 2021 are $1,776 million, $1,645 million, $1,455 million, $1,259 million and $1,135 million, respectively. At December 31, 2016 and 2015, all debt was unsecured.

INTEREST EXPENSE

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Debentures and term notes	**1,714**	1,805	1,425
Commercial paper and credit facility draws	**197**	172	71
Southern Lights project financing	**-**	-	49
Capitalized	**(321)**	(353)	(416)
	1,590	1,624	1,129

INTEREST EXPENSE

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Enbridge Inc.	**571**	970	598
Enbridge (U.S.) Inc.	**43**	54	19
Enbridge Energy Partners, L.P.	**609**	369	458
Enbridge Gas Distribution Inc.	**193**	175	154
Enbridge Income Fund	**119**	106	76
Enbridge Pipelines (Southern Lights) L.L.C.	**56**	45	36
Enbridge Pipelines Inc.	**262**	210	171
Enbridge Southern Lights LP	**14**	14	14
Midcoast Energy Partners, L.P.	**44**	34	19
Capitalized	**(321)**	(353)	(416)
	1,590	1,624	1,129

CREDIT FACILITIES

The following table provides details of the Company's committed credit facilities at December 31, 2016 and December 31, 2015.

		2016			2015
December 31,	Maturity	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge Inc.	2017-2020	**8,183**	**4,700**	**3,483**	6,988
Enbridge (U.S.) Inc.	2018-2019	**3,934**	**126**	**3,808**	4,470
Enbridge Energy Partners, L.P.	2018-2020	**3,525**	**2,293**	**1,232**	3,598
Enbridge Gas Distribution Inc.	2018-2019	**1,017**	**360**	**657**	1,010
Enbridge Income Fund	2019	**1,500**	**236**	**1,264**	1,500
Enbridge Pipelines (Southern Lights) L.L.C.	2018	**27**	**-**	**27**	28
Enbridge Pipelines Inc.	2018	**3,000**	**1,032**	**1,968**	3,000
Enbridge Southern Lights LP	2018	**5**	**-**	**5**	5
Midcoast Energy Partners, L.P.	2018	**900**	**564**	**336**	1,121
Total committed credit facilities		**22,091**	**9,311**	**12,780**	21,720

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

In addition to the committed credit facilities noted above, the Company also has $335 million (2015 - $349 million) of uncommitted demand credit facilities, of which $177 million (2015 - $185 million) were 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.

As at December 31, 2016, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $7,344 million (2015 - $11,344 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, 2016, the Company was in compliance with all debt covenants.

18. OTHER LONG-TERM LIABILITIES

December 31,	**2016**	2015
(millions of Canadian dollars)		
Regulatory liabilities	**793**	787
Derivative liabilities *(Note 24)*	**2,713**	3,950
Pension and OPEB liabilities *(Note 26)*	**597**	517
Asset retirement obligations *(Note 19)*	**230**	189
Environmental liabilities	**76**	89
Other	**572**	524
	4,981	6,056

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 11.0% (2015 - 1.7% to 9.4%). A reconciliation of movements in the Company's ARO is as follows:

December 31,	**2016**	2015
(millions of Canadian dollars)		
Obligations at beginning of year	**198**	185
Liabilities incurred	**2**	2
Liabilities settled	**(33)**	(45)
Change in estimate	**63**	30
Foreign currency translation adjustment	**(5)**	21
Accretion expense	**7**	5
Obligations at end of year	**232**	198
Presented as follows:		
Accounts payable and other *(Note 16)*	**2**	9
Other long-term liabilities *(Note 18)*	**230**	189
	232	198

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,	**2016**	2015
(millions of Canadian dollars)		
Enbridge Energy Partners, L.P.	**(99)**	412
Enbridge Energy Management, L.L.C. (EEM)	**36**	203
Enbridge Gas Distribution Inc. preferred shares	**100**	100
Renewable energy assets	**516**	561
Other	**24**	24
	577	1,300

ENBRIDGE ENERGY PARTNERS, L.P.

Noncontrolling interests in EEP represented the 80.2% (2015 - 80.0%) 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 primarily due to EEP distributing $670 million (2015 - $630 million; 2014 - $504 million) to its noncontrolling interest holders in line with EEP's objective to make quarterly distributions from its available cash, as defined in its partnership agreement and as approved by EEP's Board of Directors. This decrease was partially offset by comprehensive income attributable to noncontrolling interests in EEP during the year.

For the year ended December 31, 2016, EEP reported a net loss, as well as distributions to partners in excess of earnings attributable to partners, which reduced the carrying value of EEP's Class A and Class B common units and i-units into deficit positions. The EEP partnership agreement does not permit capital account deficits in the capital account of any limited partner and thus requires that such capital account deficits be brought to zero by additional allocations from other limited partner capital balances, to the extent such capital account balances are positive, and the General Partner on a pro-rata basis. As a result, Earnings attributable to noncontrolling interests and redeemable noncontrolling interests in the Consolidated Statements of Earnings for the year ended December 31, 2016 were higher by $816 million due to this reallocation (2015 - lower by $13 million).

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 public common unit issuance. The Company participated only to the extent to maintain its 2% General Partner (GP) interest. The common unit issuance resulted in contributions of $366 million (US$289 million) from noncontrolling interest holders.

Effective July 1, 2014, EECI, 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 decreased the Company's share of incremental cash distributions from 48% of all distributions in excess of US$0.495 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 an additional 12.6% limited partnership interest in its natural gas and NGL midstream business to 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% (2015 - 88.3%) of the listed shares of EEM not held by the Company. During the year ended December 31, 2016, the decrease in the carrying value of Noncontrolling interests in EEM is due to a comprehensive loss attributable to noncontrolling interests in EEM.

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, 2016, no preferred shares have been redeemed.

RENEWABLE ENERGY ASSETS

Renewable energy assets include the VIEs *(Note 10)* of Magic Valley, Wildcat, Keechi and New Creek wind farms. During the year ended December 31, 2016, the net decrease in the carrying value of Noncontrolling interests in Renewable energy assets was primarily due to a comprehensive loss attributable to noncontrolling interests, which were partially offset by contributions, net of distributions, received from noncontrolling interests.

REDEEMABLE NONCONTROLLING INTERESTS

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Balance at beginning of year	**2,141**	2,249	1,053
Earnings/(loss)	**268**	(3)	(11)
Other comprehensive income/(loss), net of tax			
Change in unrealized gains/(loss) on cash flow hedges	**(17)**	(7)	(15)
Other comprehensive loss from equity investees	**-**	(12)	-
Reclassification to earnings of realized cash flow hedges	**3**	2	-
Reclassification to earnings of unrealized cash flow hedges	**6**	2	-
Change in foreign currency translation adjustment	**(3)**	18	5
Other comprehensive income/(loss)	**(11)**	3	(10)
Distributions to unitholders	**(202)**	(114)	(79)
Contributions from unitholders	**591**	670	323
Reversal of cumulative redemption value adjustment attributable to ECT preferred units	**-**	(541)	-
Dilution loss on Enbridge Income Fund issuance of trust units	**(4)**	(355)	-
Dilution loss on Enbridge Income Fund equity investment	**(73)**	(132)	-
Dilution gain/(loss) on Enbridge Income Fund indirect equity investment	**(4)**	5	-
Redemption value adjustment	**686**	359	973
Balance at end of year	**3,392**	2,141	2,249

Redeemable noncontrolling interests in the Fund as at December 31, 2016 represented 45.6% (2015 - 40.7%, 2014 - 70.6%) of interests in the Fund's trust units that are held by third parties.

In April 2016, ENF completed a public equity offering of common shares for gross proceeds of $575 million and issued additional shares to Enbridge for gross proceeds of $143 million in order for Enbridge to maintain its 19.9% ownership interest in ENF. ENF used the proceeds from the common share issuances 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 40.7% to 45.6%. This resulted in contributions of $591 million, net of share issue costs, from redeemable noncontrolling interest holders and a dilution loss for redeemable noncontrolling interests of $4 million.

In April 2016, the Fund used the aggregate proceeds of $718 million from the issuance of trust units to ENF to purchase additional common units of ECT, and ECT used the aggregate proceeds of $718 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 the Fund's equity investment in ECT and a dilution loss for redeemable noncontrolling interests of $73 million for the year ended December 31, 2016.

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.

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, issued Special Interest Rights to Enbridge which are entitled to Temporary Performance Distribution Rights (TPDR) distributions. TPDR distributions occur when the Fund distribution rate exceeds a payout target and are paid in the form of Class D units. 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 resulted in a dilution gain for the Fund's indirect equity investment in EIPLP. For the year ended December 31, 2016, a dilution loss for redeemable noncontrolling interests of $4 million was recorded (2015 - dilution gain of $5 million).

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, 2016, 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

	2016		2015		2014	
December 31,	Number of Shares	Amount	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)						
Balance at beginning of year	**868**	**7,391**	852	6,669	831	5,744
Common shares issued[1]	**56**	**2,241**	-	-	9	446
Dividend Reinvestment and Share Purchase Plan (DRIP)	**16**	**795**	12	646	9	428
Shares issued on exercise of stock options	**3**	**65**	4	76	3	51
Balance at end of year	**943**	**10,492**	868	7,391	852	6,669

1 Gross proceeds - $2,300 million (2015 - nil; 2014 - $460 million); net issuance costs - $59 million (2015 - nil; 2014 - $14 million).

PREFERENCE SHARES

December 31,	**2016**		2015		2014	
	Number of Shares	**Amount**	Number of Shares	Amount	Number of Shares	Amount
(millions of Canadian dollars; number of preference shares in millions)						
Preference Shares, Series A	**5**	**125**	5	125	5	125
Preference Shares, Series B	**20**	**500**	20	500	20	500
Preference Shares, Series D	**18**	**450**	18	450	18	450
Preference Shares, Series F	**20**	**500**	20	500	20	500
Preference Shares, Series H	**14**	**350**	14	350	14	350
Preference Shares, Series J	**8**	**199**	8	199	8	199
Preference Shares, Series L	**16**	**411**	16	411	16	411
Preference Shares, Series N	**18**	**450**	18	450	18	450
Preference Shares, Series P	**16**	**400**	16	400	16	400
Preference Shares, Series R	**16**	**400**	16	400	16	400
Preference Shares, Series 1	**16**	**411**	16	411	16	411
Preference Shares, Series 3	**24**	**600**	24	600	24	600
Preference Shares, Series 5	**8**	**206**	8	206	8	206
Preference Shares, Series 7	**10**	**250**	10	250	10	250
Preference Shares, Series 9	**11**	**275**	11	275	11	275
Preference Shares, Series 11	**20**	**500**	20	500	20	500
Preference Shares, Series 13	**14**	**350**	14	350	14	350
Preference Shares, Series 15	**11**	**275**	11	275	11	275
Preference Shares, Series 17	**30**	**750**	-	-	-	-
Issuance costs		**(147)**		(137)		(137)
Balance at end of year		**7,255**		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	5.50%	$1.375	$25	-	-
Preference Shares, Series B	4.00%	$1.000	$25	June 1, 2017	Series C
Preference Shares, Series D	4.00%	$1.000	$25	March 1, 2018	Series E
Preference Shares, Series F	4.00%	$1.000	$25	June 1, 2018	Series G
Preference Shares, Series H	4.00%	$1.000	$25	September 1, 2018	Series I
Preference Shares, Series J	4.00%	US$1.000	US$25	June 1, 2017	Series K
Preference Shares, Series L	4.00%	US$1.000	US$25	September 1, 2017	Series M
Preference Shares, Series N	4.00%	$1.000	$25	December 1, 2018	Series O
Preference Shares, Series P	4.00%	$1.000	$25	March 1, 2019	Series Q
Preference Shares, Series R	4.00%	$1.000	$25	June 1, 2019	Series S
Preference Shares, Series 1	4.00%	US$1.000	US$25	June 1, 2018	Series 2
Preference Shares, Series 3	4.00%	$1.000	$25	September 1, 2019	Series 4
Preference Shares, Series 5	4.40%	US$1.100	US$25	March 1, 2019	Series 6
Preference Shares, Series 7	4.40%	$1.100	$25	March 1, 2019	Series 8
Preference Shares, Series 9	4.40%	$1.100	$25	December 1, 2019	Series 10
Preference Shares, Series 11	4.40%	$1.100	$25	March 1, 2020	Series 12
Preference Shares, Series 13	4.40%	$1.100	$25	June 1, 2020	Series 14
Preference Shares, Series 15	4.40%	$1.100	$25	September 1, 2020	Series 16
Preference Shares, Series 17	5.15%	$1.288	$25	March 1, 2022	Series 18

1 *The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board. With the exception of Series A Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15%. No other series of Preference Shares has this feature.*

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 *With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect 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), 2.7% (Series 16), 4.1% (Series 18); 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 13 million (2015 - 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,	**2016**	2015	2014
(number of common shares in millions)			
Weighted average shares outstanding	**911**	847	829
Effect of dilutive options	**7**	-	11
Diluted weighted average shares outstanding	**918**	847	840

For the year ended December 31, 2016, 10,803,672 anti-dilutive stock options (2015 - 36,005,043; 2014 - 6,058,580) with a weighted average exercise price of $52.92 (2015 - $40.26; 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 14 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, 2016	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	**32,788**	**40.31**		
Options granted	**6,373**	**44.05**		
Options exercised[1]	**(5,364)**	**29.73**		
Options cancelled or expired	**(888)**	**49.26**		
Options outstanding at end of year	**32,909**	**42.51**	**6.3**	**335**
Options vested at end of year[2]	**18,355**	**37.11**	**4.9**	**286**

1 The total intrinsic value of ISO exercised during the year ended December 31, 2016 was $123 million (2015 - $126 million; 2014 - $117 million) and cash received on exercise was $37 million (2015 - $43 million; 2014 - $37 million).

2 The total fair value of options vested under the ISO Plan during the year ended December 31, 2016 was $36 million (2015 - $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,	**2016**	2015	2014
Fair value per option *(Canadian dollars)*[1]	**7.37**	6.48	5.53
Valuation assumptions			
Expected option term *(years)*[2]	**5**	5	5
Expected volatility[3]	**25.1%**	19.9%	16.9%
Expected dividend yield[4]	**4.4%**	3.2%	2.9%
Risk-free interest rate[5]	**0.8%**	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 $7.01 (2015 - $6.22; 2014 - $5.45) for Canadian employees and US$6.60 (2015 - 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, 2016 for ISO was $43 million (2015 - $35 million; 2014 - $29 million). At December 31, 2016, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the ISO Plan was $50 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, 2016, 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, 2016, all performance targets have been met and the options are exercisable until August 15, 2020.

December 31, 2016	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	**3,217**	**39.75**		
Options exercised[1]	**(335)**	**41.29**		
Options outstanding at end of year	**2,882**	**39.57**	**3.2**	**38**
Options vested at end of year[2]	**2,409**	**39.34**	**3.2**	**32**

1 The total intrinsic value of PSO exercised during the year ended December 31, 2016 was $7 million (2015 - $43 million; 2014 - nil) and cash received on exercise was $3 million (2015 - $13 million; 2014 - nil).

2 The total fair value of options vested under the PSO Plan during the year ended December 31, 2016 was $2 million (2015 - $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, 2016 for PSO was $3 million (2015 - $3 million; 2014 - $3 million). At December 31, 2016, unrecognized compensation cost related to non-vested stock-based compensation arrangements granted under the PSO Plan was $2 million. The cost is expected to be fully recognized over a weighted average period of approximately one year.

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 2016 expense, multipliers of two, were used for each of the 2014, 2015 and 2016 PSU grants.

December 31, 2016	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	**536**		
Units granted	**294**		
Units cancelled	**(14)**		
Units matured[1]	**(295)**		
Dividend reinvestment	**35**		
Units outstanding at end of year	**556**	**1.5**	**54**

1 The total amount paid during the year ended December 31, 2016 for PSU was $22 million (2015 - $35 million; 2014 - $36 million).

Compensation expense recorded for the year ended December 31, 2016 for PSU was $33 million (2015 - $12 million; 2014 - $40 million). As at December 31, 2016, unrecognized compensation expense related to non-vested units granted under the PSU Plan was $30 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, 2016	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	**1,906**		
Units granted	**972**		
Units cancelled	**(154)**		
Units matured[1]	**(992)**		
Dividend reinvestment	**122**		
Units outstanding at end of year	**1,854**	**1.4**	**105**

1 The total amount paid during the year ended December 31, 2016 for RSU was $56 million (2015 - $45 million; 2014 - $45 million).

Compensation expense recorded for the year ended December 31, 2016 for RSU was $51 million (2015 - $47 million; 2014 - $44 million). As at December 31, 2016, unrecognized compensation expense related to non-vested units granted under the RSU Plan was $62 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, 2016, 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, 2016	**(688)**	**(795)**	**3,365**	**37**	**(287)**	**1,632**
Other comprehensive income/(loss) retained in AOCI	**(216)**	**171**	**(665)**	**(5)**	**(45)**	**(760)**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**147**	**-**	**-**	**-**	**-**	**147**
Commodity contracts[2]	**(11)**	**-**	**-**	**-**	**-**	**(11)**
Foreign exchange contracts[3]	**1**	**-**	**-**	**-**	**-**	**1**
Other contracts[4]	**(18)**	**-**	**-**	**-**	**-**	**(18)**
Amortization of pension and OPEB actuarial loss prior service costs[5]	**-**	**-**	**-**	**-**	**21**	**21**
	(97)	**171**	**(665)**	**(5)**	**(24)**	**(620)**
Tax impact						
Income tax on amounts retained in AOCI	**91**	**(5)**	**-**	**5**	**11**	**102**
Income tax on amounts reclassified to earnings	**(52)**	**-**	**-**	**-**	**(4)**	**(56)**
	39	**(5)**	**-**	**5**	**7**	**46**
Balance at December 31, 2016	**(746)**	**(629)**	**2,700**	**37**	**(304)**	**1,058**

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
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 (income)/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	(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	91	-	-	-	-	91
	77	49	-	(5)	(25)	96
Balance at December 31, 2015	(688)	(795)	3,365	37	(287)	1,632

(millions of Canadian dollars)	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
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 (income)/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 income/(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 via execution of floating to fixed interest rate swaps with an average swap rate of 2.4%.

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 via execution of floating to fixed interest rate swaps with an average swap rate of 3.7%.

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, 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, 2016 or 2015.

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, 2016	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	**101**	**3**	**5**	**109**	**(103)**	**6**
Interest rate contracts	**3**	**-**	**-**	**3**	**(3)**	**-**
Commodity contracts	**9**	**-**	**232**	**241**	**(125)**	**116**
	113	**3**	**237**	**353**	**(231)**	**122**
Deferred amounts and other assets *(Note 13)*						
Foreign exchange contracts	**1**	**3**	**69**	**73**	**(72)**	**1**
Interest rate contracts	**8**	**-**	**-**	**8**	**(6)**	**2**
Commodity contracts	**7**	**-**	**61**	**68**	**(22)**	**46**
Other contracts	**1**	**-**	**1**	**2**	**-**	**2**
	17	**3**	**131**	**151**	**(100)**	**51**
Accounts payable and other *(Note 16)*						
Foreign exchange contracts	**-**	**(268)**	**(727)**	**(995)**	**103**	**(892)**
Interest rate contracts	**(452)**	**-**	**(131)**	**(583)**	**3**	**(580)**
Commodity contracts	**-**	**-**	**(359)**	**(359)**	**125**	**(234)**
Other contracts	**(1)**	**-**	**(3)**	**(4)**	**-**	**(4)**
	(453)	**(268)**	**(1,220)**	**(1,941)**	**231**	**(1,710)**
Other long-term liabilities *(Note 18)*						
Foreign exchange contracts	**-**	**(68)**	**(1,961)**	**(2,029)**	**72**	**(1,957)**
Interest rate contracts	**(268)**	**-**	**(205)**	**(473)**	**6**	**(467)**
Commodity contracts	**-**	**-**	**(211)**	**(211)**	**22**	**(189)**
	(268)	**(68)**	**(2,377)**	**(2,713)**	**100**	**(2,613)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**102**	**(330)**	**(2,614)**	**(2,842)**	**-**	**(2,842)**
Interest rate contracts	**(709)**	**-**	**(336)**	**(1,045)**	**-**	**(1,045)**
Commodity contracts	**16**	**-**	**(277)**	**(261)**	**-**	**(261)**
Other contracts	**-**	**-**	**(2)**	**(2)**	**-**	**(2)**
	(591)	**(330)**	**(3,229)**	**(4,150)**	**-**	**(4,150)**

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
	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
	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)

1 *Amount available for offset includes $17 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, 2016	2017	2018	2019	2020	2021	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**991**	**2**	**2**	**2**	**-**	**-**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**4,369**	**2,768**	**2,943**	**2,722**	**566**	**223**
Foreign exchange contracts - GBP forwards - purchase *(millions of GBP)*	**91**	**6**	**-**	**-**	**-**	**-**
Foreign exchange contracts - GBP forwards - sell *(millions of GBP)*	**-**	**-**	**89**	**25**	**27**	**144**
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**-**	**-**	**32,662**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**6,713**	**5,161**	**1,581**	**153**	**100**	**300**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**3,998**	**2,743**	**768**	**-**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**48**	**40**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(93)**	**(42)**	**(17)**	**(9)**	**-**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**(11)**	**(9)**	**-**	**-**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(8)**	**(6)**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**40**	**30**	**31**	**35**	**(3)**	**(43)**

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)*	40	40	30	31	35	(35)

The Effect of Derivative Instruments on the Consolidated 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.

	2016	2015	2014
(millions of Canadian dollars)			
Amount of unrealized gains/(loss) recognized in OCI			
Cash flow hedges			
Foreign exchange contracts	**(19)**	77	8
Interest rate contracts	**(90)**	(275)	(1,086)
Commodity contracts	**14**	9	50
Other contracts	**39**	(47)	13
Net investment hedges			
Foreign exchange contracts	**22**	(248)	(113)
	(34)	(484)	(1,128)
Amount of (gains)/loss reclassified from AOCI to earnings *(effective portion)*			
Foreign exchange contracts[1]	**2**	9	8
Interest rate contracts[2]	**145**	128	101
Commodity contracts[3]	**(12)**	(46)	4
Other contracts[4]	**(29)**	28	(7)
	106	119	106
De-designation of qualifying hedges in connection with the Canadian Restructuring Plan			
Interest rate contracts [2]	**-**	338	-
	-	338	-
Amount of (gains)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*			
Interest rate contracts[2]	**61**	21	216
Commodity contracts[3]	**-**	5	(6)
	61	26	210

1 Reported within Transportation and other services revenues and Other income/(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.

The Company estimates that a gain of $23 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 36 months as at December 31, 2016.

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,	**2016**	2015	2014
(millions of Canadian dollars)			
Foreign exchange contracts[1]	**935**	(2,187)	(936)
Interest rate contracts[2]	**73**	(363)	4
Commodity contracts[3]	**(508)**	199	1,031
Other contracts[4]	**9**	(22)	7
Total unrealized derivative fair value gain/(loss), net	**509**	(2,373)	106

1 Reported within Transportation and other services revenues (2016 - $497 million gain; 2015 - $1,383 million loss; 2014 - $496 million loss) and Other income/(expense) (2016 - $438 million gain; 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 (2016 - $52 million loss; 2015 - $328 million gain; 2014 - $741 million gain), Commodity sales (2016 - $474 million loss; 2015 - $226 million loss; 2014 - nil), Commodity costs (2016 - $38 million gain; 2015 - $99 million gain; 2014 - $303 million gain) and Operating and administrative expense (2016 - $20 million loss; 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 that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintains substantial capacity under its committed bank lines of credit to address any contingencies. 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 also 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, 2016. 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, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

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

December 31,	**2016**	2015
(millions of Canadian dollars)		
Canadian financial institutions	**39**	47
United States financial institutions	**179**	450
European financial institutions	**106**	95
Asian financial institutions	**1**	4
Other[1]	**162**	213
	487	809

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

As at December 31, 2016, the Company had provided letters of credit totalling $160 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held no cash collateral on derivative asset exposures at December 31, 2016 and $17 million of cash collateral at December 31, 2015.

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, 2016	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**109**	**-**	**109**
Interest rate contracts	**-**	**3**	**-**	**3**
Commodity contracts	**2**	**86**	**153**	**241**
	2	**198**	**153**	**353**
Long-term derivative assets				
Foreign exchange contracts	**-**	**73**	**-**	**73**
Interest rate contracts	**-**	**8**	**-**	**8**
Commodity contracts	**-**	**43**	**25**	**68**
Other contracts	**-**	**2**	**-**	**2**
	-	**126**	**25**	**151**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(995)**	**-**	**(995)**
Interest rate contracts	**-**	**(583)**	**-**	**(583)**
Commodity contracts	**(12)**	**(75)**	**(272)**	**(359)**
Other contracts	**-**	**(4)**	**-**	**(4)**
	(12)	**(1,657)**	**(272)**	**(1,941)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(2,029)**	**-**	**(2,029)**
Interest rate contracts	**-**	**(473)**	**-**	**(473)**
Commodity contracts	**-**	**(10)**	**(201)**	**(211)**
	-	**(2,512)**	**(201)**	**(2,713)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(2,842)**	**-**	**(2,842)**
Interest rate contracts	**-**	**(1,045)**	**-**	**(1,045)**
Commodity contracts	**(10)**	**44**	**(295)**	**(261)**
Other contracts	**-**	**(2)**	**-**	**(2)**
	(10)	**(3,845)**	**(295)**	**(4,150)**

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
	14	222	555	791
Long-term derivative assets				
Foreign exchange contracts	-	128	-	128
Interest rate contracts	-	18	-	18
Commodity contracts	-	121	106	227
	-	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)

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

December 31, 2016	Fair Value	Unobservable Input	Minimum Price/Volatility	Maximum Price/Volatility	Weighted Average Price/Volatility	
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	30	Forward gas price	3.65	5.62	4.77	\$/mmbtu[3]
NGL	1	Forward NGL price	0.37	1.66	1.14	\$/gallon
Power	(159)	Forward power price	26.00	78.70	48.32	\$/MWH
Commodity contracts - physical[1]						
Natural gas	(72)	Forward gas price	2.10	11.05	4.24	\$/mmbtu[3]
Crude	(91)	Forward crude price	40.97	78.94	68.58	\$/barrel
NGL	4	Forward NGL price	0.37	1.75	1.06	\$/gallon
Commodity options[2]						
Crude	4	Option volatility	22%	33%	25%	
NGL	(13)	Option volatility	32%	103%	57%	
Power	1	Option volatility	22%	51%	23%	
	(295)					

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,	**2016**	2015
(millions of Canadian dollars)		
Level 3 net derivative asset at beginning of period	**54**	149
Total loss		
Included in earnings[1]	**(113)**	136
Included in OCI	**3**	(1)
Settlements	**(239)**	(230)
Level 3 net derivative liability at end of period	**(295)**	54

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, 2016 or 2015.

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 $110 million as at December 31, 2016 (2015 - $126 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $355 million as at December 31, 2016 (2015 - $359 million). These preferred shares are entitled to a cumulative preferred dividend based on the yield of 10-year Government of Canada bonds plus a margin of 4.38%. As at December 31, 2016, the fair value of this preferred share investment approximates its face value of $580 million (2015 - $580 million).

As at December 31, 2016, the Company's long-term debt had a carrying value of $40,761 million (2015 - $41,530 million) before debt issuance cost and a fair value of $43,910 million (2015 - $41,045 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, 2016, the Company recognized an unrealized foreign exchange gain on the translation of United States dollar denominated debt of $121 million (2015 - unrealized loss of $631 million) and an unrealized gain on the change in fair value of its outstanding foreign exchange forward contracts of $21 million (2015 - unrealized loss of $250 million) in OCI. The Company recognized a realized gain of $3 million (2015 - realized gain of $4 million) in OCI associated with the settlement of foreign exchange forward contracts and also recognized a realized gain of $26 million (2015 - realized loss of $75 million) 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, 2016 (2015 - nil).

25. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings before income taxes and discontinued operations	**2,451**	11	2,173
Canadian federal statutory income tax rate	**15%**	15%	15%
Expected federal taxes at statutory rate	**368**	2	326
Increase/(decrease) resulting from:			
Provincial and state income taxes[1]	**34**	(204)	(36)
Foreign and other statutory rate differentials	**(56)**	310	394
Effects of rate-regulated accounting[2]	**(116)**	(52)	(97)
Foreign allowable interest deductions	**(107)**	(84)	(65)
Part VI.1 tax, net of federal Part I deduction	**56**	55	47
Intercompany sale of investment[3]	**6**	23	68
Non-taxable portion of gain on sale of investment to unrelated party[4]	**(61)**	-	-
Valuation allowance[5]	**22**	154	2
Noncontrolling interests	**(15)**	(28)	(28)
Other[6]	**11**	(6)	-
Income taxes on earnings before discontinued operations	**142**	170	611
Effective income tax rate	**5.8%**	1,545.5%	28.1%

1 The change in provincial and state income taxes from 2015 to 2016 reflects the increase in earnings from the Canadian operations and the decrease in earnings from the United States operations.

2 The increase in 2016 is due to the federal component of the tax effect of the 2015 impairment of regulatory receivables.

3 In November 2016, September 2015 and November 2014, certain assets were sold 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.

4 The amount in 2016 represents the federal component of the non-taxable portion of the gain on the sale of the South Prairie Region assets to unrelated party.

5 The decrease from 2015 to 2016 is due to the federal component of the tax effect of a valuation allowance on the deferred tax assets related to an outside basis temporary difference that, in 2015, was no longer more likely than not to be realized.

6 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,	**2016**	2015	2014
(millions of Canadian dollars)			
Earnings/(loss) before income taxes and discontinued operations			
Canada	**2,034**	(1,365)	114
United States	**(333)**	808	1,614
Other	**750**	568	445
	2,451	11	2,173
Current income taxes			
Canada	**74**	157	35
United States	**21**	3	(15)
Other	**4**	3	4
	99	163	24
Deferred income taxes			
Canada	**188**	(558)	(193)
United States	**(151)**	565	780
Other	**6**	-	-
	43	7	587
Income taxes on earnings before discontinued operations	**142**	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,	**2016**	2015
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment	**(3,867)**	(3,423)
Investments	**(2,938)**	(3,024)
Regulatory assets	**(439)**	(354)
Other	**(47)**	(85)
Total deferred income tax liabilities	**(7,291)**	(6,886)
Deferred income tax assets		
Financial instruments	**1,215**	1,374
Pension and OPEB plans	**219**	202
Loss carryforwards	**1,189**	848
Other	**374**	274
Total deferred income tax assets	**2,997**	2,698
Less valuation allowance	**(572)**	(538)
Total deferred income tax assets, net	**2,425**	2,160
Net deferred income tax liabilities	**(4,866)**	(4,726)
Presented as follows:[1]		
Accounts receivable and other *(Note 7)*	**-**	367
Deferred income taxes	**1,170**	839
Total deferred income tax assets	**1,170**	1,206
Accounts payable and other	**-**	(17)
Deferred income taxes	**(6,036)**	(5,915)
Total deferred income tax liabilities	**(6,036)**	(5,932)
Net deferred income tax liabilities	**(4,866)**	(4,726)

1 *Effective January 1, 2016, the Company elected to early adopt ASU 2015-17* (Note 3)*.*

A valuation allowance has 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, 2016, the Company recognized the benefit of unused tax loss carryforwards of $2,486 million (2015 - $1,754 million) in Canada which start to expire in 2025 and beyond.

As at December 31, 2016, the Company recognized the benefit of unused tax loss carryforwards of $1,287 million (2015 - $899 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 $4.1 billion (2015 - $4.0 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 Canada (Federal, Alberta and Ontario). The Company’s 2008 to 2016 taxation years are still open for audit in the Canadian jurisdictions and the 2013 to 2016 taxation years remain open for audit in the United States jurisdictions. The Company is currently under examination for income tax matters in Canada for the 2013 and 2014 taxation years. The Company is not currently under examination for income tax matters in any other material jurisdiction where it is subject to income tax.

UNRECOGNIZED TAX BENEFITS

Year ended December 31,	**2016**	2015
(millions of Canadian dollars)		
Unrecognized tax benefits at beginning of year	**65**	51
Gross increases for tax positions of current year	**27**	5
Change in translation of foreign currency	**(2)**	9
Lapses of statute of limitations	**(6)**	-
Unrecognized tax benefits at end of year	**84**	65

The unrecognized tax benefits as at December 31, 2016, 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 taxes for the year ended December 31, 2016 included $1 million recovery (2015 - $2 million expense; 2014 - nil) of interest and penalties. As at December 31, 2016, interest and penalties of $6 million (2015 - $7 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, 2016 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. 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, 2015	December 31, 2016
Gas Distribution	December 31, 2013	December 31, 2016
United States Plan	January 1, 2016	January 1, 2017

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,	**2016**	2015	**2016**	2015
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**2,551**	2,470	**308**	276
Service cost	**155**	167	**8**	8
Interest cost	**89**	98	**11**	11
Employees' contributions	**-**	-	**1**	1
Actuarial (gains)/loss	**112**	(172)	**12**	9
Benefits paid	**(108)**	(90)	**(12)**	(12)
Effect of foreign exchange rate changes	**(14)**	79	**(4)**	21
Other	**(7)**	(1)	**(12)**	(6)
Benefit obligation at end of year	**2,778**	2,551	**312**	308
Change in plan assets				
Fair value of plan assets at beginning of year	**2,229**	2,062	**115**	99
Actual return on plan assets	**168**	88	**5**	(2)
Employer's contributions	**102**	116	**9**	10
Employees' contributions	**-**	-	**1**	1
Benefits paid	**(108)**	(90)	**(12)**	(12)
Effect of foreign exchange rate changes	**(10)**	54	**(3)**	19
Other	**(1)**	(1)	**-**	-
Fair value of plan assets at end of year[1]	**2,380**	2,229	**115**	115
Underfunded status at end of year	**(398)**	(322)	**(197)**	(193)
Presented as follows:				
Deferred amounts and other assets	**5**	6	**4**	2
Accounts payable and other	**-**	-	**(7)**	(6)
Other long-term liabilities *(Note 18)*	**(403)**	(328)	**(194)**	(189)
	(398)	(322)	**(197)**	(193)

1 *Assets of $44 million (2015 - $40 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,	**2016**	2015	2014	**2016**	2015	2014
Discount rate	**4.0%**	4.2%	4.0%	**4.0%**	4.2%	3.9%
Average rate of salary increases	**3.6%**	3.6%	4.0%			

NET BENEFIT COSTS RECOGNIZED

	Pension			OPEB		
Year ended December 31,	**2016**	2015	2014	**2016**	2015	2014
(millions of Canadian dollars)						
Benefits earned during the year	**155**	167	108	**8**	8	8
Interest cost on projected benefit obligations	**89**	98	93	**11**	11	12
Expected return on plan assets	**(148)**	(142)	(123)	**(6)**	(6)	(5)
Amortization of prior service credits	**-**	-	-	**(1)**	-	-
Amortization of actuarial loss	**35**	49	28	**1**	1	-
Net defined benefit costs on an accrual basis	**131**	172	106	**13**	14	15
Defined contribution benefit costs	**3**	4	4	**-**	-	-
Net benefit cost recognized in Earnings	**134**	176	110	**13**	14	15
Amount recognized in OCI:						
Net actuarial (gains)/loss[1]	**24**	(107)	232	**12**	16	15
Net prior service credit[2]	**-**	-	-	**(12)**	(6)	-
Total amount recognized in OCI	**24**	(107)	232	**-**	10	15
Total amount recognized in Comprehensive income	**158**	69	342	**13**	24	30

1 Unamortized actuarial losses included in AOCI, before tax, were $425 million (2015 - $404 million) relating to the pension plans and $54 million (2015 - $44 million) relating to OPEB at December 31, 2016.

2 Unamortized prior service credits included in AOCI, before tax, were $13 million (2015 - $1 million) relating to OPEB at December 31, 2016.

The Company estimates that approximately $36 million related to pension plans and $1 million related to OPEB at December 31, 2016 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, 2016, an offsetting regulatory liability increased by $10 million (2015 - nil) and has been recorded to the extent pension and OPEB costs are expected to be refunded to 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,	**2016**	2015	2014	**2016**	2015	2014
Discount rate - service cost	**4.1%**	4.0%	5.0%	**4.2%**	3.9%	4.9%
Discount rate - interest cost	**4.1%**	4.0%	5.0%	**4.2%**	3.9%	4.9%
Average rate of return on plan assets	**6.6%**	6.7%	6.7%	**6.0%**	6.0%	6.0%
Average rate of salary increases	**3.6%**	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	6.6%	4.5%	2034
Other medical	4.5%	-	-
United States Plan	6.9%	4.5%	2037

A 1% increase in the assumed medical care trend rate would result in an increase of $23 million in the benefit obligation and an increase of $1 million in service and interest costs. A 1% decrease in the assumed medical care trend rate would result in a decrease of $45 million in the benefit obligation and a decrease of $2 million in service 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,	**2016**	2015	**2016**	2015
Canadian Plans	**6.6%**	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, 2016, the pension assets were invested 48.3% (2015 - 56.4%) in equity securities, 31.4% (2015 - 31.4%) in fixed income securities and 20.3% (2015 - 12.2%) in other. The OPEB assets were invested 60.0% (2015 - 59.1%) in equity securities, 39.1% (2015 - 40.0%) in fixed income securities and 0.9% (2015 - 0.9%) in other.

The following table summarizes the Company's pension financial instruments at fair value. Non-financial instruments with a carrying value of $7 million asset (2015 - $21 million asset) and refundable tax assets of $105 million (2015 - $106 million) have been excluded from the table below.

	2016				2015			
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	**47**	**-**	**-**	**47**	37	-	-	37
Fixed income securities								
Canadian government bonds	**137**	**-**	**-**	**137**	131	-	-	131
Corporate bonds and debentures	**5**	**3**	**-**	**8**	5	3	-	8
Canadian corporate bond index fund	**277**	**-**	**-**	**277**	259	-	-	259
Canadian government bond index fund	**214**	**-**	**-**	**214**	201	-	-	201
United States debt index fund	**111**	**-**	**-**	**111**	102	-	-	102
Equity								
Canadian equity securities	**138**	**-**	**-**	**138**	133	-	-	133
United States equity securities	**2**	**-**	**-**	**2**	2	-	-	2
Global equity securities	**114**	**30**	**-**	**144**	106	25	-	131
Canadian equity funds	**287**	**-**	**-**	**287**	253	-	-	253
United States equity funds	**271**	**-**	**-**	**271**	243	5	-	248
Global equity funds	**167**	**140**	**-**	**307**	161	148	-	309
Infrastructure[4]	**-**	**-**	**184**	**184**	-	-	182	182
Real estate[4]	**-**	**-**	**137**	**137**	-	-	115	115
Forward currency contracts	**-**	**4**	**-**	**4**	-	(10)	-	(10)
OPEB								
Cash and cash equivalents	**1**	**-**	**-**	**1**	2	-	-	2
Fixed income securities								
United States government and government agency bonds	**45**	**-**	**-**	**45**	46	-	-	46
Equity								
United States equity funds	**35**	**-**	**-**	**35**	34	-	-	34
Global equity funds	**34**	**-**	**-**	**34**	34	-	-	34

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,	**2016**	2015
(millions of Canadian dollars)		
Balance at beginning of year	**297**	132
Unrealized and realized gains	**22**	44
Purchases and settlements, net	**2**	121
Balance at end of year	**321**	297

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension		OPEB	
Year ended December 31,	**2016**	2015	**2016**	2015
(millions of Canadian dollars)				
Total contributions	**102**	116	**9**	10
Contributions expected to be paid in 2017	**148**		**2**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2017	2018	2019	2020	2021	2022-2026
(millions of Canadian dollars)						
Expected future benefit payments	115	121	127	134	142	829

27. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Net foreign currency gain/(loss)	**91**	(884)	(400)
Allowance for equity funds used during construction	**1**	2	3
Interest income on affiliate loans	**23**	20	20
Interest income	**3**	4	3
Noverco preferred shares dividend income	**37**	40	42
Gains on dispositions	**848**	94	38
Other	**29**	22	28
	1,032	(702)	(266)

28. SEVERANCE COSTS

Included in Operating and administrative and Other income/(expense) is $54 million and nil, respectively (2015 - $42 million and $4 million, respectively), for severance costs related to termination benefits to employees. This resulted from an enterprise-wide reduction of workforce that occurred in October 2016 and November 2015 that affected approximately 5% of the Company's workforce in each respective year. The amounts are included within Eliminations and Other.

Of the total severance costs incurred in 2016, $29 million was paid in 2016 with the remaining $25 million to be paid in 2017 and is included in Accounts payable and other as at December 31, 2016.

Of the total severance costs incurred in 2015, $22 million was paid in 2015 with the remaining $24 million paid in 2016. This amount was included in Accounts payable and other as at December 31, 2015.

29. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2016**	2015	2014
(millions of Canadian dollars)			
Accounts receivable and other	**(437)**	698	(83)
Accounts receivable from affiliates	**(7)**	82	(176)
Inventory	**(371)**	(315)	(186)
Deferred amounts and other assets	**(183)**	364	(429)
Accounts payable and other	**396**	(1,472)	(822)
Accounts payable to affiliates	**71**	(26)	34
Interest payable	**20**	31	24
Other long-term liabilities	**153**	(7)	(61)
	(358)	(645)	(1,699)

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, 2016 (2015 - $7 million; 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, 2016 were $357 million (2015 - $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, 2016, expenses related to the lease arrangement totalled $287 million (2015 - $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 $98 million (2015 - $228 million; 2014 - $315 million) from several joint venture affiliates during the year ended December 31, 2016.

Natural gas sales of $49 million (2015 - $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, 2016.

LONG-TERM NOTES RECEIVABLE FROM AFFILIATES

Amounts receivable from affiliates include a series of loans to Vector and other affiliates totalling $130 million and $140 million, respectively (2015 - $149 million and $3 million, 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, 2016, 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[1,2]	10,661	3,660	1,461	1,249	1,100	996	2,195
Capital and operating leases	631	105	62	56	52	51	305
Maintenance agreements	394	54	40	35	18	16	231
Land lease commitments	356	13	14	13	14	13	289
Total	12,042	3,832	1,577	1,353	1,184	1,076	3,020

1 *Includes capital and operating commitments.*

2 *Includes commitments for transportation service agreements totalling $618 million which assume a light to heavy crude oil ratio of 80:20 on certain pipelines and a power charge of $0.06 per barrel.*

ENBRIDGE ENERGY PARTNERS, L.P.

As at December 31, 2016, Enbridge holds an approximate 35.3% (2015 - 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

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 evaluate the need for additional remediation activities and is performing the necessary 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.

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, 2016, EEP’s total cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge) since December 31, 2015 and 2014. This includes a reduction of estimated remediation efforts offset by an increase in civil penalties under the Clean Water Act of the United States, 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, 2016. Despite the efforts EEP has made to ensure the reasonableness of its estimate, 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.

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. In October 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$53 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, 2016, 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. On May 1 of each year, the commercial liability insurance program is renewed and includes coverage that is consistent with coverage considered customary for its industry and includes coverage for environmental incidents excluding costs for fines and penalties.

Enbridge has renewed its comprehensive property and liability insurance programs with a liability program aggregate limit of US$900 million, which includes sudden and accidental pollution liability. The insurance programs are effective May 1, 2016 through April 30, 2017. In the unlikely event that 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.

A majority of the costs incurred in connection with the crude oil release for Line 6B, other than fines and penalties, 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, 2016, 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 prior or existing insurance policy. As at December 31, 2016, 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 asserted 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 includes only one insurer.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Two actions or claims are pending against Enbridge, EEP or their affiliates in United States 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.

Line 6A and 6B Fines and Penalties

As at December 31, 2016, included in EEP's total estimated costs related to the Line 6B crude oil release were US$69 million in fines and penalties. Of this amount, US$61 million relates to civil penalties under the Clean Water Act of the United States, which EEP fully accrued but have not paid, pending approval of the Consent Decree, as described below.

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 had 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.

Consent Decree

On July 20, 2016, a Consent Decree was filed with the United States District Court for the Western District of Michigan Southern Division (the Court). The Consent Decree is EEP's signed settlement agreement with the EPA and the United States Department of Justice regarding Lines 6A and 6B crude oil releases. Pursuant to the Consent Decree, EEP will pay US$62 million in civil penalties: US$61 million in respect of Line 6B and US$1 million in respect of Line 6A. The Consent Decree will take effect upon approval by the Court.

In addition to the monetary fines and penalties discussed above, the Consent Decree calls for replacement of Line 3, which EEP initiated in 2014 and is currently under regulatory review in the State of Minnesota. The Consent Decree contains a variety of injunctive measures, including, but not limited to, enhancements to EEP's comprehensive in-line inspection-based spill prevention program; enhanced measures to protect the Straits of Mackinac; improved leak detection requirements; installation of new valves to control product loss in the event of an incident; continued enhancement of control room operations; and improved spill response capabilities. Collectively, these measures build on continuous improvements implemented since 2010 to EEP's leak detection program, control centre operations and emergency response program. EEP estimates the total cost of these measures to be approximately

US$110 million, most of which is already incorporated into existing long-term capital investment and operational expense planning and guidance. Compliance with the terms of the Consent Decree is not expected to materially impact the overall financial performance of EEP or the Company.

AUX SABLE

Notice of Violation

In September 2014, Aux Sable US received a Notice and Finding of Violation (NFOV) from the United States 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 believed to be an exceedance of currently permitted limits for Volatile Organic Material. In April 2015, a second NFOV from the EPA was received in connection with this potential exceedance. Aux Sable engaged in discussions with the EPA to evaluate the impacts and ultimate resolution of these issues, including with respect to a draft Consent Decree, and those discussions are continuing. The Consent Decree, when finalized, is not expected to have a material impact.

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to an NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim. While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on the Company's consolidated financial position or results of operations.

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 February 17, 2017, the Company announced it had acquired an effective 50% interest in the partnership that will construct the 497-MW Hohe See Offshore Wind Project. Enbridge will partner with state-owned German utility EnBW in the construction and operation of this late-design project, with the target in-service date of 2019. The Hohe See Offshore Wind Project is located in the North Sea, 98 kilometres (61 miles) off the coast of Germany and will be constructed under fixed-price engineering, procurement, construction and installation contracts, which have been secured with key suppliers. The Hohe See Offshore Wind Project is backed by a government legislated 20-year revenue support mechanism. Enbridge's total investment in this project through the project's completion and in-service date in 2019 is expected to be approximately $1.7 billion (€1.07 billion), including planned spend of approximately $0.6 billion (€0.44 billion) throughout 2017.

On February 15, 2017, EEP completed its previously disclosed transaction to acquire an effective 27.6% interest in the Bakken Pipeline System for a purchase price of US$1.5 billion. The Bakken Pipeline System connects the prolific Bakken formation in North Dakota to markets in eastern PADD II and the United States Gulf Coast, providing customers with access to premium markets at a competitive cost. The Bakken Pipeline System consists of the Dakota Access Pipeline and the Energy Transfer Crude Oil Pipeline projects. The Dakota Access Pipeline consists of 1,886 kilometres (1,172 miles) of 30-inch pipeline from the Bakken/Three Forks production area in North Dakota to Patoka, Illinois. It is expected to initially deliver in excess of 470,000 bpd of crude oil and has the potential to be expanded to 570,000 bpd. The Energy Transfer Crude Oil Pipeline consists of 100 kilometres (62 miles) of new 30-inch diameter pipe, 1,104 kilometres (686 miles) of converted 30-inch diameter pipe, and 64 kilometres (40 miles) of converted 24-inch diameter pipe from Patoka, Illinois to Nederland, Texas.

On January 27, 2017, Enbridge announced that it had entered into a merger agreement through a wholly-owned subsidiary, whereby it will take private MEP by acquiring all of the outstanding publicly-held common units of MEP. Total consideration to be paid by Enbridge for these units will be approximately US$170 million and the transaction is expected to close in the second quarter of 2017. In addition, pursuant to an on-going strategic review of EEP, further joint funding actions with EEP were announced. Specifically, Enbridge and EEP entered into an agreement for the joint funding of the United States portion of the Line 3 Replacement Program (U.S. L3R Program), whereby Enbridge and EEP will fund 99% and 1%, respectively, of the project development and construction costs. Enbridge has reimbursed EEP approximately US$450 million for capital expenditures on the project to date and will fund 99% of the expenditures through construction. EEP will retain an option to acquire up to 40% of the U.S. L3R Program at book value, once the project is completed and in service. EEP also used a portion of the proceeds reimbursed by Enbridge under the U.S. L3R joint funding arrangement to acquire an additional 15% interest in the cash-generating Eastern Access projects pursuant to an existing joint funding agreement for approximately US$360 million. The strategic review of EEP is ongoing and it is currently expected that any resulting actions will be announced early in the second quarter of 2017. Any such contemplated actions are not expected to be material to Enbridge's previously published financial projections.