ENBRIDGE INC
Form 6-K
July 29, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 6-K

Report of Foreign Issuer

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

the Securities Exchange Act of 1934

Dated July 29, 2016

Commission file number 001-15254

ENBRIDGE INC.

(Exact name of Registrant as specified in its charter)

200, 425 1st Street S.W.

Calgary, Alberta, Canada T2P 3L8

(Address of principal executive offices and postal code)

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

Form 20-F	Form 40-F	P

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

Yes	No	P

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

Yes	No	P

THIS REPORT ON FORM 6-K SHALL BE DEEMED TO BE INCORPORATED BY REFERENCE IN THE REGISTRATION STATEMENTS ON FORM S-8 (FILE NO. 333-145236, 333-127265, 333-13456, 333-97305 AND 333-6436), FORM F-3 (FILE NO. 33-77022) AND FORM F-10 (FILE NO. 333-198566) OF ENBRIDGE INC. AND TO BE PART THEREOF FROM THE DATE ON WHICH THIS REPORT IS FURNISHED, TO THE EXTENT NOT SUPERSEDED BY DOCUMENTS OR REPORTS SUBSEQUENTLY FILED OR FURNISHED.

The following documents are being submitted herewith:

- Interim Report to Shareholders for the six months ended June 30, 2016.
- Interactive Data File.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE INC.
(Registrant)

Date: July 29, 2016

By: /s/ Tyler W. Robinson
Tyler W. Robinson

Vice President & Corporate Secretary

ENBRIDGE INC.

MANAGEMENT S DISCUSSION AND ANALYSIS

June 30, 2016

MANAGEMENT S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2016

This Management s Discussion and Analysis (MD&A) dated July 29, 2016 should be read in conjunction with the unaudited interim consolidated financial statements and notes thereto of Enbridge Inc. (Enbridge or the Company) as at and for the three and six months ended June 30, 2016, prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited amended consolidated financial statements and MD&A for the year ended December 31, 2015 filed on May 12, 2016. All financial measures presented in this MD&A are expressed in Canadian dollars, unless otherwise indicated. Additional information related to the Company, including its Annual Information Form, is available on SEDAR at www.sedar.com.

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

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 (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 comparative three and six months ended June 30, 2015.

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

LIQUIDS PIPELINES

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

GAS DISTRIBUTION

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

GAS PIPELINES AND PROCESSING

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

GREEN POWER AND TRANSMISSION

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

ENERGY SERVICES

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

ELIMINATIONS AND OTHER

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

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. It 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 than originally anticipated, given the severity and longevity of the wildfires. On average Enbridge s mainline system deliveries were lower by approximately 255,000 barrels per day (bpd) during the months of May and June 2016, which represents an approximate 10% decrease in throughput compared with the throughput that the Company was delivering prior to the wildfires. The impact of reduced system deliveries on revenues negatively impacted the Company s adjusted EBIT and available cash flow from operations (ACFFO) by approximately $74 million for the three and six months ended June 30, 2016. They also reduced the Company s adjusted earnings and adjusted earnings per share by $26 million and $0.03, respectively, for the three and six months ended June 30, 2016. Oil sands production substantially came back online by the end of June 2016 and throughput on the Company s mainline system and overall system utilization are expected to return to levels anticipated at the outset of the year, during the third quarter of 2016.

2

CONSOLIDATED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**643**	1,097	**2,255**	952
Gas Distribution	**83**	78	**322**	317
Gas Pipelines and Processing	**19**	(411)	**80**	(375)
Green Power and Transmission	**41**	43	**90**	102
Energy Services	**(7)**	67	**(13)**	64
Eliminations and Other	**(48)**	65	**173**	(376)
Earnings/(loss) before interest and income taxes	**731**	939	**2,907**	684
Interest expense	**(369)**	(284)	**(781)**	(535)
Income taxes recovery/(expense)	**(10)**	(232)	**(427)**	53
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**20**	224	**(41)**	134
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Earnings attributable to common shareholders	**301**	577	**1,514**	194
Earnings per common share	**0.33**	0.68	**1.69**	0.23
Diluted earnings per common share	**0.33**	0.67	**1.67**	0.23

EARNINGS/(LOSS) BEFORE INTEREST AND INCOME TAXES

For the three and six months ended June 30, 2016, EBIT was $731 million and $2,907 million, respectively, compared with $939 million and $684 million for the three and six months ended June 30, 2015. As discussed below in *Adjusted EBIT*, the Company has continued to deliver strong earnings growth from a majority of its businesses, offset partly by the impacts of the northeastern Alberta wildfires as discussed above. The positive impact of this growth and the comparability of the Company s earnings are also 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 changes in unrealized derivative fair value gains and losses. For the three months ended June 30, 2016, the Company s EBIT reflected a $98 million unrealized derivative fair value loss compared with $366 million of unrealized derivative fair value gain in the corresponding 2015 period. For the six months ended June 30, 2016, the Company s EBIT reflected an $834 million unrealized derivative fair value gain compared with $1,042 million of unrealized derivative fair value loss in the corresponding 2015 period. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks which create volatility in short-term earnings. Over the long term, Enbridge believes its hedging program supports the reliable cash flows and dividend growth upon which the Company s investor value proposition is based.

In addition, the comparability of period-over-period EBIT was impacted by the recognition of an impairment of $176 million ($103 million after-tax attributable to Enbridge) related 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 in the second quarter of 2016. The comparability of period-over-period EBIT 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 Enbridge Energy Partners, L.P. s (EEP) natural gas and NGL businesses. Also impacting the comparability of period-over-period EBIT was a $21 million charge ($12 million after-tax attributable to Enbridge) for costs incurred to bring pipelines and facilities back into service following the northeastern Alberta wildfires in the second quarter of 2016.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Earnings attributable to common shareholders were $301 million for the three months ended June 30, 2016, or $0.33 per common share, compared with earnings of $577 million, or $0.68 per common share, for the three months ended June 30, 2015. Earnings attributable to common shareholders were $1,514 million for the six months ended June 30, 2016, or $1.69 per common share, compared with earnings of $194 million, or $0.23 per common share, for the six months ended June 30, 2015.

In addition to the factors discussed in *Earnings/(Loss) Before Interest and Income Taxes* above and in *Adjusted Earnings*, the comparability of Earnings attributable to common shareholders is impacted by period-over-period variation in interest and income tax expenses, as well as the variation in earnings attributable to noncontrolling interests and redeemable noncontrolling interests. The comparability of the Company s six-month period-over-period operating results was also impacted by 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.

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 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; expectations regarding the impacts of the wildfires in northeastern Alberta, including on adjusted EBIT and ACFFO; 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; 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; expectations regarding the impact of the dividend payout policy and dividend payout expectation; and strategic alternatives currently being evaluated in connection with the United States sponsored vehicles strategy.

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, NGL and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labour and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company s projects; anticipated in-service dates; weather; impact of the wildfires in northeastern Alberta; 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 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 and regulatory approvals on construction and in-service schedules.

Enbridge s forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, dividend policy, project approval and support, weather, economic and competitive conditions, public opinion, changes in tax law and tax rate increases, exchange rates, interest rates, commodity prices, *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) 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) and ACFFO give useful information to investors and shareholders as they provide increased transparency and insight into the performance of the Company. Management uses adjusted EBIT and adjusted earnings/(loss) to set targets and to assess the performance of the Company. Management also uses ACFFO to assess the performance of the Company and to set its dividend payout target. Adjusted EBIT, adjusted EBIT for each segment, adjusted earnings/(loss) and ACFFO are not measures that have standardized meaning prescribed by U.S. GAAP and are not U.S. GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers.

The tables below summarize the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATION EBIT TO ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Earnings before interest and income taxes	**731**	939	**2,907**	684
Adjusting items[1]:				
Changes in unrealized derivative fair value (gains)/loss[2]	**98**	(366)	**(834)**	1,042
Goodwill impairment loss	**-**	440	**-**	440
Assets and investment impairment loss	**187**	20	**187**	20
Unrealized intercompany foreign exchange (gains)/loss	**(5)**	16	**55**	(55)
Hydrostatic testing	**-**	-	**(12)**	-
Make-up rights adjustments	**48**	(15)	**115**	(13)
Northeastern Alberta wildfires pipelines and facilities restart costs	**21**	-	**21**	-
Leak remediation costs, net of leak insurance recoveries	**1**	8	**16**	(4)
Warmer/(colder) than normal weather	**(9)**	8	**8**	(37)
Employee severance and restructuring costs	**8**	-	**8**	-
Gains on sale of non-core assets	**-**	(28)	**-**	(28)
Project development and transaction costs	**3**	18	**3**	21
Other	**6**	9	**(11)**	10
Adjusted earnings before interest and income taxes	**1,089**	1,049	**2,463**	2,080
Interest expense	**(369)**	(284)	**(781)**	(535)
Income taxes recovery/(expense)	**(10)**	(232)	**(427)**	53
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**20**	224	**(41)**	134
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Adjusting items in respect of[3]:				
Interest expense	**6**	(7)	**24**	(49)
Income taxes	**(121)**	132	**120**	(267)
Noncontrolling interests and redeemable noncontrolling interests	**(88)**	(307)	**(95)**	(301)
Adjusted earnings	**456**	505	**1,119**	973

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 losses are presented net of amounts realized on the settlement of derivative contracts during the applicable period.

3 These items were impacted by adjustments for unusual, non-recurring and non-operating factors as enumerated under adjusting items above. Also included in income taxes is 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.

NON-GAAP RECONCILIATION   ADJUSTED EBIT TO ADJUSTED EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars, except per share amounts)				
Liquids Pipelines	**922**	809	**2,006**	1,540
Gas Distribution	**73**	96	**313**	294
Gas Pipelines and Processing	**90**	74	**177**	164
Green Power and Transmission	**40**	43	**88**	100
Energy Services	**47**	78	**48**	106
Eliminations and Other	**(83)**	(51)	**(169)**	(124)
Adjusted earnings before interest and income taxes	**1,089**	1,049	**2,463**	2,080
Interest expense[1]	**(363)**	(291)	**(757)**	(584)
Income taxes[1]	**(131)**	(100)	**(307)**	(214)
Noncontrolling interests and redeemable noncontrolling interests[1]	**(68)**	(83)	**(136)**	(167)
Preference share dividends	**(71)**	(70)	**(144)**	(142)
Adjusted earnings	**456**	505	**1,119**	973
Adjusted earnings per common share	**0.50**	0.60	**1.25**	1.15

1 *These balances are presented net of adjusting items.*

Adjusted EBIT

For the three and six months ended June 30, 2016, adjusted EBIT was $1,089 million and $2,463 million, respectively, an increase of $40 million and $383 million over the corresponding three and six-month periods in 2015.

Growth in consolidated adjusted EBIT was largely driven by stronger contributions from the 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 Project (Southern Access Extension) in the fourth quarter of 2015, which have provided access to the eastern Canada and Patoka markets, respectively. The Canadian Mainline and Regional Oil Sands System contributions increased in the first half of 2016 primarily due to higher period-over-period mainline system throughput that resulted from strong oil sands production in western Canada combined with contributions from new assets placed into service. 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. The northeastern Alberta 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 Enbridge s downstream pipelines deliveries, 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 the three and six-month periods in 2016. Growth in Canadian Mainline adjusted EBIT was also affected by a lower average International Joint Tariff (IJT) Residual Benchmark Toll, which decreased effective April 1, 2016 and, together with the impact of the wildfires, resulted in a quarter-over-quarter decrease in Canadian Mainline adjusted EBIT.

The Lakehead System delivered strong operating performance driven by higher throughput and contributions from new assets placed into service in 2015. Deliveries to the Lakehead System from the Canadian Mainline were lower during the second quarter as a result of the wildfires, but the impact on financial performance was relatively modest due to the higher Lakehead System Local

Toll. The Company also benefitted from stronger adjusted EBIT contributions from the United States Mid-Continent and Gulf Coast systems, mainly attributable to increased transportation revenues resulting from an increase in the level of committed take-or-pay volumes and higher tariffs on Flanagan South Pipeline (Flanagan South).

Within the Gas Distribution segment, EGD adjusted EBIT increased for the first half of 2016 compared with the first half of 2015, primarily attributable to higher distribution charges arising from growth in EGD s rate base, customer growth and lower storage and transportation costs. In the second quarter of 2016, adjusted EBIT generated by EGD was lower compared with the corresponding 2015 period, primarily due to the relative timing and recognition of final rates approved by the Ontario Energy Board (OEB) for each of 2015 and 2016. In particular, the positive impact of the OEB s final rate determination for 2015 was reflected in the second quarter of that year, whereas the impact of the 2016 determination was reflected in the first quarter of 2016. The second quarter decrease in adjusted EBIT caused by these quarterly timing impacts was partially offset by higher distribution charges arising from growth in EGD s rate base and customer growth, and it is expected that adjusted EBIT at EGD for the full 2016 year will grow as a result of these factors.

The Gas Pipelines and Processing segment benefitted from strong contributions from Alliance Pipeline under its new services framework that came into effect in the fourth quarter of 2015, higher throughput on certain Enbridge Offshore Pipelines (Offshore) and contributions from the Tupper Main and Tupper West gas plants (the Tupper Plants) following their acquisition on April 1, 2016. These positive effects were partially offset by weaker contributions from Aux Sable due to lower fractionation margins, and lower volumes on US Midstream pipelines due to reduced drilling by producers.

The Green Power and Transmission segment delivered lower period-over-period adjusted EBIT as a result of weaker wind resources at certain facilities. Adjusted EBIT for the first half of 2016 was also negatively impacted by disruptions at certain eastern Canadian wind farms in the first quarter of 2016 due to weather conditions which caused icing of blades.

Adjusted EBIT from Energy Services decreased for the three and six months ended June 30, 2016 as lower oil prices compressed crude oil location and quality differentials.

Adjusted Earnings

Adjusted earnings were $456 million, or $0.50 per common share, for the three months ended June 30, 2016 compared with $505 million, or $0.60 per common share, for the three months ended June 30, 2015. Adjusted earnings were $1,119 million, or $1.25 per common share, for the six months ended June 30, 2016 compared with $973 million, or $1.15 per common share, for the six months ended June 30, 2015.

The quarter-over-quarter decrease in adjusted earnings reflected the operating factors as discussed above in *Adjusted EBIT*. The impacts of the northeastern Alberta wildfires on adjusted earnings and adjusted earnings per share were approximately $26 million and $0.03, respectively. Adjusted earnings period-over-period were also impacted by the effects of interest expense, income taxes and noncontrolling interests as discussed below.

Interest expense for the three and six-month periods ended June 30, 2016 was higher compared with the corresponding 2015 periods resulting from debt to fund asset growth and the impact of refinancing construction debt with longer-term debt financing. The amount of interest capitalized period-over-period also decreased as a result of projects coming into service.

Income taxes increased in the first half of 2016 largely due to the period-over-period increase in earnings.

Adjusted earnings attributable to noncontrolling interests and redeemable noncontrolling interests decreased for the three and six months ended June 30, 2016 compared with the same periods in 2015. The redeemable noncontrolling interests in the Fund Group (comprising Enbridge Income Fund (the Fund), Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and its subsidiaries and investees) decreased mainly as a result of the quarter-over-quarter decrease in contributions from the Fund Group s Canadian liquids pipelines businesses reflecting the impacts of the northeastern Alberta wildfires in the second quarter of 2016 as discussed in *Impact of Wildfires in Northeastern Alberta*. Adjusted earnings attributable to noncontrolling interests in EEP decreased in the first half of 2016. Although EEP reflected higher contributions from its liquids pipelines businesses, there was a decrease in

EEP s overall period-over-period contribution to adjusted earnings primarily due to higher interest expense.

Finally, interest expense, income taxes and noncontrolling interests and redeemable noncontrolling interests were also impacted by adjustments for unusual, non-recurring and non-operating factors.

NON-GAAP RECONCILIATION 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 June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**1,089**	1,049	**2,463**	2,080
Depreciation and amortization1	**555**	485	**1,114**	959
Maintenance capital2	**(144)**	(164)	**(295)**	(316)
	1,500	1,370	**3,282**	2,723
Interest expense3	**(363)**	(291)	**(757)**	(584)
Current income taxes3	**(34)**	(50)	**(81)**	(76)
Preference share dividends	**(71)**	(71)	**(144)**	(142)
Distributions to noncontrolling interests	**(178)**	(166)	**(362)**	(324)
Distributions to redeemable noncontrolling interests	**(53)**	(26)	**(95)**	(53)
Cash distributions in excess of equity earnings3	**43**	80	**21**	126
Other non-cash adjustments	**24**	(38)	**118**	(60)
Available cash flow from operations (ACFFO)	**868**	808	**1,982**	1,610
1 Depreciation and amortization:				
Liquids Pipelines	***336***	*287*	***682***	*567*
Gas Distribution	***84***	*80*	***164***	*157*
Gas Pipelines and Processing	***75***	*68*	***149***	*133*
Green Power and Transmission	***47***	*46*	***95***	*92*
Energy Services	***1***	-	***1***	-
Eliminations and Other	***12***	*4*	***23***	*10*
	555	*485*	***1,114***	*959*
2 Maintenance capital:				
Liquids Pipelines	***(28)***	*(78)*	***(72)***	*(140)*
Gas Distribution	***(84)***	*(51)*	***(166)***	*(114)*
Gas Pipelines and Processing	***(12)***	*(8)*	***(23)***	*(15)*
Green Power and Transmission	***(1)***	-	***(1)***	-
Eliminations and Other	***(19)***	*(27)*	***(33)***	*(47)*
	(144)	*(164)*	***(295)***	*(316)*

3 These balances are presented net of adjusting items.

Available Cash Flow from Operations

ACFFO was $868 million for the three months ended June 30, 2016 compared with $808 million for the three months ended June 30, 2015. ACFFO was $1,982 million for the six months ended June 30, 2016 compared with $1,610 million for the six months ended June 30, 2015. The Company experienced strong period-over-period growth in ACFFO which was driven by the same factors as discussed in *Adjusted EBIT* above. However, the impacts of the northeastern Alberta wildfires negatively impacted period-over-period ACFFO by $74 million for the three and six months ended June 30, 2016.

Maintenance capital expenditures decreased period-over-period as higher expenditures in the Company s Gas Distribution and Gas Pipelines and Processing segments were more than offset by lower maintenance capital expenditures in the Liquids Pipelines segment which reflected a shift in the timing of maintenance activity within the year. Maintenance capital expenditures across all business segments are expected to be higher in 2016 over the full year as the Company continues to invest in its maintenance capital program to support the safety and reliability of its operations.

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

Additionally, increased distributions to noncontrolling interests in EEP and to redeemable noncontrolling interests in the Fund Group partially offset other increases to ACFFO. Distributions were higher in the first half of 2016 compared with the first half of 2015 mainly as a result of increased public ownership in EEP and the Fund Group.

The ACFFO also includes cash distributions from the Company s equity investments. Equity earnings from such investments for the 2016 periods were higher compared with the corresponding periods of 2015; however, the cash distributions remained relatively stable period-over-period. Cash distributions were $182 million and $368 million for the three and six months ended June 30, 2016, respectively, compared with $189 million and $368 million of cash distributions received for the three and six months ended June 30, 2015.

NON-GAAP RECONCILIATION ACFFO

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Cash provided by operating activities - continuing operations	**1,370**	1,361	**3,231**	2,882
Adjusted for changes in operating assets and liabilities[1]	**(87)**	(105)	**(209)**	(252)
	1,283	1,256	**3,022**	2,630
Distributions to noncontrolling interests	**(178)**	(166)	**(362)**	(324)
Distributions to redeemable noncontrolling interests	**(53)**	(26)	**(95)**	(53)
Preference share dividends	**(71)**	(71)	**(144)**	(142)
Maintenance capital expenditures[2]	**(144)**	(164)	**(295)**	(316)
Significant adjusting items:				
Weather normalization	**(7)**	6	**6**	(27)
Project development and transaction costs	**3**	5	**3**	7
Realized inventory revaluation allowance[3]	**(15)**	(32)	**(283)**	(165)
Employee severance and restructuring costs	**8**	-	**8**	-
Other items	**42**	-	**122**	-
Available cash flow from operations (ACFFO)	**868**	808	**1,982**	1,610

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.

RECENT DEVELOPMENTS

COMMON SHARE ISSUANCES

On March 1, 2016, the Company completed the issuance of 56.5 million common shares at a price of $40.70 per share for gross proceeds of approximately $2.3 billion. This issuance was inclusive of 7.4 million common shares issued on exercise of the full amount of the underwriters over-allotment option. 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.

On April 20, 2016, the Company s affiliate Enbridge Income Fund Holdings Inc. (ENF) completed a public equity offering of 20.4 million common shares at a price of $28.25 per share (the Offering Price) for gross proceeds of $575 million. Concurrent with the closing of the equity offering, Enbridge subscribed for 5.1

million common shares at a price of $28.25 per share, for total proceeds of $143 million, on a private placement basis to maintain its 19.9% ownership interest in ENF. ENF used the proceeds from the sale of the common shares to subscribe for additional ordinary trust units of the Fund (Fund Units) at the Offering Price. The proceeds from the issuance of the Fund Units will be used to fund the secured growth capital programs of Enbridge Pipelines (Athabasca) Inc. and Enbridge Pipelines Inc. (EPI). Upon closing of the transaction, Enbridge s total economic interest in the Fund Group, through its ownership of ENF and directly through investment in Fund Group entities, decreased from 89.3% to 86.9%. As at June 30, 2016, Enbridge s total economic interest in the Fund Group remained at 86.9%.

UNITED STATES SPONSORED VEHICLE STRATEGY

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

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

LIQUIDS PIPELINES

Lakehead System Line 6B Crude Oil Release

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

As at June 30, 2016, EEP s cumulative cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($195 million after-tax attributable to Enbridge). This includes a reduction of estimated remediation efforts offset by an increase in estimated 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 as at June 30, 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.

Insurance Recoveries

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.

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 June 30, 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 policies. As at June 30, 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 was predicated on the outcome of the recovery from that insurer. EEP received a partial recovery 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 Enbridge filed 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.

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

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators have initiated investigations into the Line 6B crude oil release. Three 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 the Company s results of operations or financial condition.

Line 6B Fines and Penalties

As at June 30, 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 for.

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) that is EEP s signed settlement agreement with the United States 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, following a comment period.

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 center 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.

Seaway Pipeline Regulatory Matters

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011. In February 2014, the Federal Energy Regulatory Commission (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. The case was assigned to an Administrative Law Judge (ALJ). The oral hearing with respect to the application began on July 7, 2016 and concluded on July 11, 2016. The ALJ will issue an initial decision on the application by December 1, 2016. The ALJ s initial decision will then be considered by the FERC Commissioners, who can accept or reject the initial decision in full or in part. It is unclear when the FERC Commissioners decision with respect to market based rates will be received as there is no timing requirement applicable to it.

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.

GAS PIPELINES AND PROCESSING

Aux Sable Environmental Protection Agency Matter

In September 2014, Aux Sable received a Notice and Finding of Violation (NFOV) from the EPA for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable s Channahon, Illinois facility. As part of the ongoing process of responding to the September 2014 NFOV, Aux Sable discovered what it 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. On May 20, 2016, Aux Sable received a draft Consent Decree from the EPA and settlement discussions are expected to continue during the third quarter of 2016. The final settlement amount is not expected to be material.

GAS DISTRIBUTION

Enbridge Gas New Brunswick Inc. Regulatory Matters

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

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

13

GROWTH PROJECTS   COMMERCIALLY SECURED PROJECTS

The following table summarizes the current status of the Company s commercially secured projects, organized by business segment.

(Canadian dollars, unless stated otherwise)		Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
LIQUIDS PIPELINES					
1.	Eastern Access (EEP) [3]	US$0.3 billion	US$0.3 billion	2016	Complete
2.	JACOS Hangingstone Project (the Fund Group)	$0.2 billion	$0.1 billion	2017	Under construction
3.	Regional Oil Sands Optimization Project (the Fund Group)	$2.6 billion	$1.9 billion	2017	Under construction
4.	Norlite Pipeline System (the Fund Group)[4]	$1.3 billion	$0.5 billion	2017	Under construction
5.	Lakehead System Mainline Expansion (EEP)[3]	US$0.8 billion	US$0.6 billion	2016-2019 (in phases)	Under construction
6.	Canadian Line 3 Replacement Program (the Fund Group)	$4.9 billion	$1.3 billion	2019	Pre-construction
7.	U.S. Line 3 Replacement Program (EEP)	US$2.6 billion	US$0.4 billion	2019	Pre-construction
8.	Sandpiper Project (EEP)[5]	US$2.6 billion	US$0.8 billion	2019	Pre-construction
GAS DISTRIBUTION					
9.	Greater Toronto Area Project	$0.9 billion	$0.8 billion	2016	Complete
GAS PIPELINES AND PROCESSING					
10.	Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-TBD (in phases)	Complete
11.	Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	TBD	Complete
12.	Eaglebine Gathering (EEP)	US$0.2 billion	US$0.1 billion	2015-TBD (in phases)	Complete (Phase 1)

13.	Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Complete
14.	Tupper Main and Tupper West Gas Plants	$0.5 billion	$0.5 billion	2016	Acquisition completed
15.	Aux Sable Extraction Plant Expansion	US$0.1 billion	US$0.1 billion	2016	Substantially complete
16.	Stampede Oil Pipeline	US$0.2 billion	US$0.1 billion	2018	Under construction
GREEN POWER AND TRANSMISSION					
17.	New Creek Wind Project	US$0.2 billion	US$0.1 billion	2016	Under construction
18.	Rampion Offshore Wind Project	$0.8 billion (£0.37 billion)	$0.3 billion (£0.13 billion)	2018	Under construction

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

2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to June 30, 2016.

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

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

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

The description of each of the above projects is provided in the Company s 2015 annual MD&A. Any significant updates since February 19, 2016, the date of the original filing of the Company s MD&A for the year ended December 31, 2015, are discussed below.

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. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to Enbridge Energy, Limited Partnership (EELP) for its interests in the Eastern Access projects until the second quarter of 2016. EELP holds partnership interests in assets that are jointly funded by Enbridge and EEP, including the Eastern Access projects. In return, until the second quarter of 2016, Enbridge s capital funding contribution requirements to the Eastern Access projects were netted against its foregone cash distribution.

JACOS Hangingstone Project (the Fund Group)

The Company is undertaking the construction of facilities, which will provide transportation services to the Japan Canada Oil Sands Limited (JACOS) Hangingstone Oil Sands Project (JACOS Hangingstone). The project, which will provide capacity of 40,000 bpd, has been delayed at the shippers request and is now expected to enter service in the first quarter of 2017. The estimated cost of the project remains at approximately $0.2 billion, with expenditures to date of approximately $0.1 billion.

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. Based on current engineering design, the project is now expected to 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.

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 Alberta Clipper expansion remains subject to an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd. The timing of receipt of the amendment to the Presidential border crossing permit to allow for increased flow on Alberta Clipper across the border cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining this amendment.

The remaining scope of the Lakehead System Mainline Expansion includes the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois. The remaining work includes additional tankage which is expected to cost approximately US$0.4 billion with various completion dates that began in the third quarter of 2015 and are expected to continue through the third quarter of 2016. In 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 United States portion of the Line 3 Replacement Program (U.S. L3R Program) and Sandpiper. The expenditures incurred to date are approximately US$0.6 billion.

EEP will operate the project on a cost-of-service basis. The Lakehead System Mainline Expansion is funded 75% by Enbridge and 25% by EEP. EEP has the option to increase its economic interest held by up to an additional 15% at cost. On July 30, 2015, Enbridge and EEP reached an agreement to forego distributions to EELP for its interests in the Lakehead System Mainline Expansion until the second quarter of 2016. EELP holds partnership interests in assets that are jointly funded by Enbridge and EEP, including the Lakehead System Mainline Expansion. In return, until the second quarter of 2016, Enbridge s capital funding contribution requirements to the Lakehead System Mainline Expansion were netted 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 Line 3 Replacement Program (L3R Program). The L3R Program includes the Canadian portion of the L3R Program (Canadian L3R Program) and the U.S. L3R Program.

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.

Several months prior to the National Energy Board (NEB) hearing held in 2015, Enbridge reached a settlement agreement with landowner associations representing Line 3 landowners in Canada and as a result these parties withdrew from the hearing process and have expressed their support for the project. The general terms of the settlement agreements were applied to all landowners directly impacted by the project, resulting in the resolution of nearly all outstanding landowner concerns. The NEB found these agreements and the resolution of outstanding concerns with nearly all potentially impacted landowners to be a persuasive factor in favour of the reasonableness of Enbridge s decommissioning plan.

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 (the Cabinet) to issue a Certificate of Public Convenience and Necessity (the Certificate) for the construction and operation of the pipeline and related facilities. A decision by the 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 has directed Federal agencies to conduct an assessment of direct and upstream greenhouse gas (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). As a result, Enbridge anticipates a decision from the Cabinet by the end of November 2016 and the issuance of the Certificate by the NEB in the days following the Cabinet decision.

Also in April 2016, Environment and Climate Change Canada published a draft review of related upstream GHG emissions estimates for Enbridge s Canadian L3R Program and opened a 30 day public comment period on the draft, which closed in May 2016 with six parties providing comments on the draft report. The draft review 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 draft 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. On May 25, 2016, the Federal consultation process on the Canadian L3R Program was expanded with Natural Resources Canada undertaking consultations with Indigenous peoples impacted by the Canadian L3R Program and posting an online questionnaire to solicit input from interested and/or impacted parties. The results of these two efforts will be combined with the results of the GHG study and are expected to be presented to the Cabinet for deliberation in the fall of 2016 prior to the Cabinet making its decision on whether to approve the project.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in early 2019 at an estimated capital cost of approximately $4.9 billion, with expenditures to date of approximately $1.3 billion. With a delay in construction arising from a longer than anticipated permitting process, the cost of this project is expected to increase. The Company continues to review the estimated cost of this project. Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the Competitive Toll Settlement (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 Minnesota Public Utilities Commission (MNPUC). The MNPUC found both the Certificate of Need and Route Permit applications for the U.S. L3R Program through Minnesota to be complete and sent the Certificate of Need application to the ALJ for a pre-hearing meeting to establish a schedule. With respect to the Route Permit, the Minnesota Department of Commerce (DOC) held public scoping meetings in August 2015. As a result of the Court of Appeals decision with respect to EEP s Sandpiper pipeline project discussed below, the ALJ requested direction on how to proceed with the Certificate of Need process for Line 3. On February 1, 2016, the MNPUC issued a written order (the U.S. L3R Order) joining the Line 3 Certificate of Need and Route Permit dockets, requiring the DOC to prepare an 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 an 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 has 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 is addressing the comments received on the draft EIS scope and last reported that it would issue its scoping recommendations to the MNPUC in July 2016. Since then, no scoping recommendation has been issued. EEP now expects it to be issued in August 2016.

The ALJ who is overseeing the Line 3 Certificate of Need and Route Permit processes held a scheduling conference on May 16, 2016 at which the timeline for the scoping recommendation was discussed. A second pre-hearing conference has been scheduled for August 10, 2016 to further discuss the regulatory schedule.

Subject to regulatory and other approvals, the U.S. L3R Program is now expected to be completed in early 2019 at an estimated capital cost of approximately US$2.6 billion, with expenditures to date of approximately US$0.4 billion. The Company continues to review the impact of the U.S. L3R Order on the U.S. L3R Program s schedule and cost estimates. The U.S. L3R Program will be jointly funded by Enbridge and EEP at participation levels that are subject to finalization. EEP will recover the costs based on its existing Facilities Surcharge Mechanism with the initial term of the agreement being 15 years. For the purpose of the toll surcharge, the agreement specifies a 30-year recovery of the capital based on a cost of service methodology.

Sandpiper Project (EEP)

As part of the Light Oil Market Access Program initiative, EEP plans to undertake Sandpiper, which will expand and extend EEP s North Dakota feeder system. The Bakken takeaway capacity of the North Dakota System will be expanded by 225,000 bpd to a total of 580,000 bpd. The proposed expansion will involve construction of a 965-kilometre (600-mile) line from Beaver Lodge Station near Tioga, North Dakota to the Superior, Wisconsin mainline system terminal. The new line will twin the existing 210,000 bpd North Dakota System mainline, which now terminates at Clearbrook Terminal in Minnesota, by adding 250,000 bpd of capacity between Tioga and Berthold, North Dakota and 225,000 bpd of capacity between Berthold and Clearbrook, both with new 24-inch diameter pipelines, as well as adding 375,000 bpd of capacity between Clearbrook and Superior with a new 30-inch diameter pipeline.

EEP is in the process of obtaining the appropriate permits for constructing Sandpiper in Minnesota. The project requires both a Certificate of Need and Route Permit from the MNPUC. Sandpiper and U.S. L3R Program are being processed independently by the MNPUC; however, because the two projects follow the same route in eastern Minnesota, the MNPUC has required that the agencies prepare the environmental assessment jointly for the two projects before publishing a separate EIS for each project.

On August 3, 2015, the MNPUC issued an order granting a Certificate of Need and a separate order restarting the Route Permit proceedings. On September 14, 2015, the Minnesota Court of Appeals reversed the MNPUC s Certificate of Need order stating that an EIS must be prepared prior to reaching a final decision in cases where proceedings have been separated and handled sequentially. On January 11, 2016, the MNPUC issued a written order (the Sandpiper Order) re-joining the Certificate of Need and Route Permit process, requiring the DOC to commence preparation of an EIS, ordering the Office of Administrative Hearings to recommence processing the Certificate of Need and Route Permit applications but to take judicial notice of the record already developed for the Certificate of Need and to require that a final EIS be issued before the Certificate of Need and Route Permit processes commence. On February 1, 2016, EEP filed a Petition for Reconsideration of the requirement to provide an EIS ahead of the commencement of the Certificate of Need and Route Permit noted in the Sandpiper Order. At a hearing held on March 24, 2016, the MNPUC denied the Petition for Reconsideration.

With the issuance of the EAW on April 11, 2016, the MNPUC has 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 and concluded on May 13, 2016. The DOC is addressing the comments received on the draft EIS scope and last reported that it would issue its scoping recommendations to the MNPUC in July 2016. Since then, no scoping recommendation has been issued. EEP now expects it to be issued in August 2016.

The ALJ overseeing the Sandpiper Certificate of Need and Route Permit processes held a scheduling conference in June 2016 at which the DOC provided a draft EIS schedule. A second meeting will be held on August 10, 2016 to further discuss the regulatory schedule.

Subject to regulatory and other approvals, Sandpiper is expected to be completed in early 2019 at an estimated capital cost of approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.8 billion. The Company continues to review the impact of the Sandpiper Order on the project s schedule and cost estimates.

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, which includes installation and upgrade of two additional stations through 2017, is estimated to be approximately $0.9 billion, with expenditures incurred to date of approximately $0.8 billion.

GAS PIPELINES AND PROCESSING

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. A deposit of approximately $0.1 billion was made in the first quarter of 2016, with the remaining purchase price paid upon closing of the transaction in April 2016. 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 2014, the Company approved the expansion of fractionation capacity and related facilities at the Aux Sable extraction and fractionation plant located in Channahon, Illinois. The expansion will serve the growing NGL-rich gas stream on the Alliance Pipeline, allow for effective management of Alliance Pipeline s downstream natural gas heat content and support additional production and sale of NGL products. The expansion is expected to provide approximately 24,500 bpd of incremental fractionation capacity and is now expected to be placed into service in the third quarter of 2016. The Company s share of the project cost is approximately US$0.1 billion.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following project has been announced by the Company, but has not yet met Enbridge s criteria to be classified as commercially secured. The Company also has additional attractive projects under development that have not yet progressed to the point of public announcement.

LIQUIDS PIPELINES

Northern Gateway Project

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

In June 2014, the Governor in Council (GIC) approved Northern Gateway, subject to 209 conditions following the recommendation from the Joint Review Panel (JRP). Nine applications to the Federal Court of Appeal (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 Federal Court consolidated the nine applications into one proceeding. The hearing of these applications commenced in Vancouver, British Columbia, on October 1, 2015 and concluded on October 8, 2015. 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 was unacceptably flawed, and for that reason it quashed the Certificates of Public Convenience and Necessity (the Certificates) and sent the matter back to the GIC for redetermination.

The GIC options include redoing the Phase IV consultation, after which it can direct the NEB to issue the Certificates, direct the NEB to dismiss the application for the Certificates, or it can remit the matter back to the NEB for further consideration. The deadline for seeking Leave to Appeal to the Supreme Court of Canada is in late September 2016.

On July 8, 2016, the NEB informed Northern Gateway that in light of the Federal Court decision, it was suspending indefinitely its consideration of all filings related to the conditions attached to the Certificates.

The Company continues to work closely with its customers in advancing this project to open West Coast market access and also continues to build relationships and trust with communities and Aboriginal groups along the proposed route.

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

The in-service date of the project will be dependent upon the timing and outcome of an Appeal to the Supreme Court of Canada, if any, continued commercial support, receipt of regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities). Of the 48 Aboriginal groups eligible to participate as equity owners, 31 have signed up to do so.

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

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

FINANCIAL RESULTS

LIQUIDS PIPELINES

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Canadian Mainline	**177**	220	**486**	380
Lakehead System	**359**	259	**712**	533
Regional Oil Sands System	**88**	84	**181**	170
Mid-Continent and Gulf Coast	**160**	122	**341**	206
Southern Lights Pipeline	**39**	36	**80**	72
Bakken System	**54**	48	**108**	109
Feeder Pipelines and Other	**45**	40	**98**	70
Adjusted earnings before interest and income taxes	**922**	809	**2,006**	1,540
Canadian Mainline - changes in unrealized derivative fair value gains/(loss)	**(12)**	256	**556**	(574)
Canadian Mainline - Line 9B costs incurred during reversal	**-**	(1)	**-**	(2)
Lakehead System - changes in unrealized derivative fair value loss	**(4)**	(5)	**(5)**	(8)
Lakehead System - hydrostatic testing	**-**	-	**12**	-
Lakehead System - leak remediation costs	**(1)**	-	**(21)**	-
Regional Oil Sands System - northeastern Alberta wildfires pipelines and facilities restart costs	**(21)**	-	**(21)**	-
Regional Oil Sands System - leak insurance recoveries	**-**	-	**5**	12
Regional Oil Sands System - make-up rights adjustment	**(20)**	8	**(34)**	14
Regional Oil Sands System - leak remediation and long- term pipeline stabilization costs	**-**	(8)	**-**	(8)
Mid-Continent and Gulf Coast - changes in unrealized derivative fair value loss	**(1)**	(3)	**(1)**	(4)
Mid-Continent and Gulf Coast - make-up rights adjustment	**(28)**	5	**(78)**	(5)
Southern Lights Pipeline - changes in unrealized derivative fair value gains/(loss)	**(6)**	15	**26**	(33)
Bakken System - make-up rights adjustment	**3**	5	**-**	8
Bakken System - changes in unrealized derivative fair value loss	**(2)**	(3)	**(3)**	(4)
Feeder Pipelines and Other - investment impairment loss	**(176)**	-	**(176)**	-
Feeder Pipelines and Other - derecognition of regulatory balances	**(6)**	-	**(6)**	-
Feeder Pipelines and Other - gain on sale of non-core assets	**-**	22	**-**	22
Feeder Pipelines and Other - make-up rights adjustment	**(2)**	(3)	**(2)**	(5)
Feeder Pipelines and Other - project development costs	**(3)**	-	**(3)**	(1)
Earnings before interest and income taxes	**643**	1,097	**2,255**	952

Additional details on items impacting Liquids Pipelines EBIT include:

- Canadian Mainline EBIT for each period 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.

- Lakehead System EBIT for 2016 included recoveries in relation to hydrostatic testing performed on Line 2B in 2015.

- Lakehead System EBIT for 2016 included charges related to estimated costs, before insurance recoveries, associated with the Line 6B crude oil release. Refer to *Recent Developments Liquids Pipelines Lakehead System Line 6B Crude Oil Release.*

- Regional Oil Sands System EBIT for 2016 and 2015 included insurance recoveries, as well as charges in 2015, associated with the Line 37 crude oil release which occurred in June 2013.

- Regional Oil Sands System EBIT for each period included make-up rights adjustments to recognize revenue for certain long-term take-or-pay contracts rateably over the contract life. 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.

- Southern Lights Pipeline EBIT for each period reflected changes in unrealized fair value gains and losses on derivative financial instruments used to manage foreign exchange risk exposure on United States dollar cash flows from the Southern Lights Class A units.

- 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.

Canadian Mainline

Canadian Mainline adjusted EBIT increased for the first half of 2016 compared with the corresponding 2015 period. Positively impacting adjusted EBIT was 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 in the first half of 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 first half of 2016.

The positive effect of increased capacity on Canadian Mainline throughput discussed above was partially offset in the second quarter 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 Enbridge s downstream pipelines deliveries, including the Canadian Mainline. The reduced system deliveries negatively impacted Canadian Mainline adjusted EBIT by approximately $30 million for the second quarter of 2016. For further details on the wildfires, refer to *Impact of Wildfires in Northeastern Alberta.*

Period-over-period 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.

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 three and six months ended June 30, 2016, the effective hedged rate for the translation of Canadian Mainline United States dollar transactional revenues was $1.034 and $1.076, respectively, compared with $1.097 and $1.088 for the corresponding 2015 periods.

Other factors which partially offset the increase in Canadian Mainline adjusted EBIT for the first half of the year included higher power costs associated with higher throughput and higher operating and administrative expense to support increased business activities.

The decrease in Canadian Mainline IJT Residual Benchmark Toll and lower exchange rate, together with the impact of the northeastern Alberta wildfires, resulted in a quarter-over-quarter decrease in Canadian Mainline adjusted EBIT.

In 2015, the Company commenced collecting, in its tolls, NEB mandated future abandonment costs from shippers. Approximately $10 million and $22 million were recorded for the three and six months ended June 30, 2016, respectively (2015 - $8 million and $17 million), but these amounts were offset by a corresponding increase in operating and administrative expense in the respective periods.

Supplemental information related to the Canadian Mainline for the three and six months ended June 30, 2016 and 2015 is provided below:

June 30,	**2016**	2015
(United States dollars per barrel)		
IJT Benchmark Toll[1]	**$4.07**	$4.02
Lakehead System Local Toll[2]	**$2.61**	$2.39
Canadian Mainline IJT Residual Benchmark Toll[3]	**$1.46**	$1.63

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, 2015, the IJT Benchmark Toll increased from US$4.02 to US$4.07. 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. 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 April 1, 2015, the Canadian Mainline IJT Residual Benchmark Toll increased from US$1.53 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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(thousands of bpd)				
Average throughput volume[1]	**2,242**	2,073	**2,392**	2,141

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

Lakehead System

Lakehead System adjusted EBIT increased for the first half of 2016 compared with the first half of 2015. The period-over-period increase in adjusted EBIT reflected stronger operating performance, as well as the favourable effect of translating United States dollar earnings to Canadian dollars at a higher average United States to Canadian dollar exchange rate (Exchange Rate) in the first half of 2016 compared with the corresponding 2015 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Lakehead System adjusted EBIT was US$279 million and US$535 million for the three and six months ended June 30, 2016, respectively, compared with US$211 million and US$433 million for the corresponding 2015 periods. The period-over-period increases reflected 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 for the first half of 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, as a result of the northeastern Alberta wildfires. The reduced system deliveries negatively impacted Lakehead System adjusted EBIT by approximately $38 million for the three and six-month periods in

2016. Also partially offsetting the increase in adjusted EBIT for the first half of 2016 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 Lakehead System adjusted EBIT for the three and six months ended June 30, 2016 was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in 2016 due to the strengthening United States dollar versus the Canadian dollar. The Exchange Rate was $1.29 and $1.33 for the three and six months ended June 30, 2016, respectively, compared with $1.23 and $1.24 in the corresponding 2015 periods. 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*.

Throughput Volume

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(thousands of bpd)				
Average throughput volume[1]	**2,440**	2,208	**2,588**	2,269

1 *Throughput volume represents mainline system deliveries to the United States midwest and eastern Canada.*

Regional Oil Sands System

Regional Oil Sands System adjusted EBIT increased for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods. Higher 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. The increase in adjusted EBIT was partially offset by the effects of the wildfires in northeastern Alberta, as discussed under *Impact of Wildfires in Northeastern Alberta*, which negatively impacted Regional Oil Sands System adjusted EBIT by approximately $6 million for the second quarter of 2016.

Mid-Continent and Gulf Coast

Mid-Continent and Gulf Coast adjusted EBIT increased for the first half of 2016 compared with the corresponding 2015 period. The period-over-period increase in adjusted EBIT reflected stronger operating performance, as well as the favourable effect of translating United States dollar earnings to Canadian dollars at a higher Exchange Rate in the first half of 2016 compared with the corresponding 2015 period.

Excluding the impact of foreign exchange translation to Canadian dollars, Mid-Continent and Gulf Coast adjusted EBIT was US$125 million and US$257 million for the three and six months ended June 30, 2016, respectively, compared with US$98 million and US$165 million for the corresponding 2015 periods. The increase in adjusted EBIT for the three and six-month periods primarily reflected increased transportation revenues resulting from an increase in the level of committed take-or-pay volumes and higher tariffs on Flanagan South. 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.

As noted above, positively impacting period-over-period adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in the first half of 2016 due to the strengthening United States dollar versus the Canadian dollar. Similar to Lakehead System, a portion of Mid-Continent and Gulf Coast United States dollar EBIT is hedged as part of the Company s enterprise-wide financial risk management program and realized gains and losses from the derivative instruments used to hedge foreign exchange risk arising from the Company s investment in United States businesses are reported within Eliminations and Other. For further details refer to *Eliminations and Other*.

Bakken System

Bakken System adjusted EBIT for the first half of 2016 decreased slightly compared with the corresponding 2015 period. The period-over-period decrease in adjusted EBIT reflected lower rates and lower rail revenues on the United States portion of the Bakken System, partially offset by the translation of United States dollar earnings to Canadian dollars at a higher Exchange Rate in the first half of 2016 compared with the corresponding 2015 period. The decrease in adjusted EBIT was also partially offset by higher contributions from the Canadian portion of the Bakken System in the second quarter of 2016, primarily due to increased demand resulting from the enhanced downstream capacity on the mainline system. The higher contribution from the Canadian portion of the Bakken System was also a key driver for the quarter-over-quarter increase in Bakken System adjusted EBIT.

Excluding the impact of foreign exchange translation to Canadian dollars, adjusted EBIT from Bakken System s United States portion was US$36 million and US$73 million for the three and six months ended June 30, 2016, respectively, compared with US$35 million and US$82 million for the corresponding 2015 periods. The decrease in the first half of 2016 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 each of April 1, 2015 and 2016, as well as lower rail revenues related to EEP s Berthold rail facility. 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 period-over-period adjusted EBIT was the favourable effect of translating United States dollar earnings at a higher Exchange Rate in the first half of 2016 due to the strengthening United States dollar versus the Canadian dollar. Similar to Lakehead System, a part of the United States portion of the Bakken System United States dollar EBIT is hedged as part of the Company s enterprise-wide financial risk management program and realized gains and losses from the derivative instruments used to hedge foreign exchange risk arising from the Company s investment in United States businesses are reported within Eliminations and OtherFor further details refer to *Eliminations and Other*.

Feeder Pipelines and Other

Feeder Pipelines and Other adjusted EBIT increased for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods, primarily reflecting new contributions from Southern Access Extension which was placed into service in the fourth quarter of 2015. These benefits were partially offset during the second quarter of 2016 by a decrease in adjusted EBIT from Eddystone Rail, primarily attributable to market conditions which impacted volumes at the rail facility, as well as lower contributions from Toledo resulting from refinery turnarounds which negatively impacted Toledo volumes.

GAS DISTRIBUTION

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Enbridge Gas Distribution Inc. (EGD)	**72**	84	**247**	222
Noverco Inc. (Noverco)	**(5)**	5	**33**	36
Other Gas Distribution and Storage	**6**	7	**33**	36
Adjusted earnings before interest and income taxes	**73**	96	**313**	294
EGD - (warmer)/colder than normal weather	**9**	(8)	**(8)**	37
Noverco - changes in unrealized derivative fair value gains/(loss)	**1**	(10)	**-**	(14)
Noverco - recognition of regulatory balances	**-**	-	**17**	-
Earnings before interest and income taxes	**83**	78	**322**	317

Additional details on items impacting Gas Distribution EBIT include:

- Noverco EBIT for 2016 included the recognition of regulatory assets in relation to employee future benefits.

EGD

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

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Adjusted earnings before interest and income taxes	**72**	84	**247**	222
Interest expense	**(44)**	(37)	**(81)**	(75)
Income taxes	**-**	(3)	**(20)**	(30)
Adjusting items in respect of:				
Income taxes	**2**	(2)	**(2)**	10
Adjusted earnings	**30**	42	**144**	127
EGD - (warmer)/colder than normal weather	**7**	(6)	**(6)**	27
Earnings attributable to common shareholders	**37**	36	**138**	154

EGD adjusted earnings increased for the first half of 2016 compared with the first half of 2015, primarily attributable to higher distribution charges arising from growth in EGD s rate base, customer growth and lower storage and transportation costs. These positive effects were partially offset by lower transactional services revenues, mainly relating to pipeline optimization activities, and higher interest expense. For the second quarter of 2016, adjusted earnings generated by EGD were lower compared with the corresponding 2015 period, primarily due to the relative timing and recognition of final rates approved by the OEB for each of 2015 and 2016. In particular, the positive impact of the OEB s final rate determination for 2015 was reflected in the second quarter of that year, whereas the impact of the 2016 determination was reflected in the first quarter of 2016. The second quarter decrease in adjusted earnings caused by these quarterly timing impacts, as well as higher interest expense and higher earnings sharing expense, was partially offset by higher distribution charges arising from growth in EGD s rate base and customer growth.

Noverco

Noverco adjusted EBIT decreased for the three months ended June 30, 2016 compared with the corresponding 2015 period, primarily reflecting the timing of equity earnings adjustments between quarters. Excluding the impact of these adjustments, Noverco adjusted EBIT for the six months ended June 30, 2016 was comparable with the corresponding 2015 period.

GAS PIPELINES AND PROCESSING

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Aux Sable	**1**	2	**(2)**	8
Alliance Pipeline	**47**	37	**96**	77
Vector Pipeline	**6**	6	**15**	15
Canadian Midstream	**28**	19	**49**	40
Enbridge Offshore Pipelines (Offshore)	**8**	4	**21**	6
US Midstream	**4**	8	**6**	25
Other	**(4)**	(2)	**(8)**	(7)
Adjusted earnings before interest and income taxes	**90**	74	**177**	164
Aux Sable - accrual for commercial arrangements	**-**	(16)	**-**	(16)
Alliance Pipeline - derecognition of regulatory balances	**-**	8	**-**	8
Alliance Pipeline - changes in unrealized derivative fair value gains/(loss)	**-**	4	**12**	(8)
Offshore - gain on sale of non-core assets	**-**	6	**-**	6
US Midstream - goodwill impairment loss	**-**	(440)	**-**	(440)
US Midstream - assets impairment loss	**(11)**	(20)	**(11)**	(20)
US Midstream - changes in unrealized derivative fair value loss	**(59)**	(27)	**(97)**	(70)
US Midstream - make-up rights adjustment	**(1)**	-	**(1)**	1
Earnings/(loss) before interest and income taxes	**19**	(411)	**80**	(375)

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

- US Midstream EBIT for 2015 included a goodwill impairment charge related to the Company s United States natural gas and NGL businesses due to a prolonged decline in commodity prices which has reduced producers expected drilling programs and negatively impacted volumes on the Company s natural gas and NGL systems.

- US Midstream EBIT for 2016 reflected asset impairment charges in relation to certain non-core trucking assets that the Company is planning to sell.

- US Midstream EBIT for 2015 reflected asset impairment charges in relation to a non-core propylene pipeline asset, following finalization of a contract restructuring with the primary customer.

- US Midstream EBIT for each period reflected changes in unrealized fair value losses on derivative financial instruments used to risk manage commodity price exposures.

Aux Sable

Aux Sable adjusted EBIT decreased for the first half of 2016 compared with the corresponding 2015 period, primarily reflecting lower fractionation margins that resulted from continuing weakness in the commodity price environment.

Alliance Pipeline

Alliance Pipeline adjusted EBIT, which represents EBIT from the Company s indirect 50% equity investment in Alliance Pipeline, increased for the three and six months ended June 30, 2016, compared with the corresponding 2015 periods, primarily due to lower operating costs and higher revenues resulting from strong demand for seasonal firm service under Alliance Pipeline s new services framework that commenced in the fourth quarter of 2015. The increase in adjusted EBIT was partially offset by the absence of non-renewal fees for the United States portion of Alliance Pipeline.

Canadian Midstream

Canadian Midstream adjusted EBIT increased for the three and six months ended June 30, 2016, compared with the three and six months ended June 30, 2015. The period-over-period increase reflected contributions from the Tupper Plants following their acquisition on April 1, 2016.

Offshore

Excluding the impact of foreign exchange translation to Canadian dollars, Offshore adjusted EBIT was US$6 million and US$16 million for the three and six months ended June 30, 2016, respectively, compared with US$3 million and US$5 million for the corresponding 2015 periods. The period-over-period increases in Offshore adjusted EBIT primarily reflected contributions from Heidelberg Oil Pipeline which was placed into service in January 2016 and an increase in volumes in the Mississippi Canyon Gas Pipeline. Favourable impact of translating United States dollar earnings at a higher Exchange Rate during the first half of 2016 also contributed to higher period-over-period adjusted EBIT.

US Midstream

Excluding the impact of foreign exchange translation to Canadian dollars, US Midstream adjusted EBIT was US$3 million and US$5 million for the three and six months ended June 30, 2016, respectively, compared with US$6 million and US$20 million for the corresponding 2015 periods. The period-over-period 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. As at June 30, 2016, Enbridge s ownership interest in US Midstream, held through EEP, was 19.1% (December 31, 2015 - 19.2%).

GREEN POWER AND TRANSMISSION

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Green Power and Transmission	**40**	43	**88**	100
Adjusted earnings before interest and income taxes	**40**	43	**88**	100
Green Power and Transmission - changes in unrealized derivative fair value gains	**1**	-	**2**	2
Earnings before interest and income taxes	**41**	43	**90**	102

Green Power and Transmission adjusted EBIT decreased for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods. Green Power and Transmission reflected lower adjusted EBIT in the first half of 2016 as a result of weaker wind resources experienced at certain facilities, as well as disruptions at certain eastern Canadian wind farms in the first quarter of 2016 due to weather conditions which caused icing of blades. Partially offsetting these negative impacts was a slight improvement in quarter-over-quarter solar resources at certain facilities.

ENERGY SERVICES

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Energy Services	**47**	78	**48**	106
Adjusted earnings before interest and income taxes	**47**	78	**48**	106
Energy Services - changes in unrealized derivative fair value loss	**(54)**	(11)	**(61)**	(42)
Earnings/(loss) before interest and income taxes	**(7)**	67	**(13)**	64

Additional details on items impacting Energy Services EBIT include:

- Energy Services earnings/(loss) before interest and income taxes for each period reflected changes in unrealized fair value loss 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.

Energy Services adjusted EBIT decreased for the three and six months ended June 30, 2016 compared with the corresponding 2015 periods. The period-over-period decreases in adjusted EBIT reflected weaker performance from Energy Services Canadian and United States operations, partially offset by the translation of United States dollar earnings to Canadian dollars at a higher Exchange Rate in the first half of 2016. From its United States operations, adjusted EBIT for the three and six months ended June 30, 2016 was US$22 million and US$27 million, respectively, compared with US$56 million and US$68 million for the corresponding 2015 periods.

Adjusted EBIT decreased when compared with the first half of 2015 as low oil prices compressed crude oil location and quality differentials. 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.

ELIMINATIONS AND OTHER

Earnings before Interest and Income Taxes

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	**2016**	2015
(millions of Canadian dollars)				
Operating and administrative	**(19)**	(11)	**(34)**	(28)
Realized foreign exchange derivative loss	**(64)**	(48)	**(151)**	(99)
Other	**-**	8	**16**	3
Adjusted loss before interest and income taxes	**(83)**	(51)	**(169)**	(124)

Changes in unrealized derivative fair value gains/(loss)	**38**	150	**405**	(287)
Unrealized intercompany foreign exchange gains/(loss)	**5**	(16)	**(55)**	55
Employee severance and restructuring costs	**(8)**	-	**(8)**	-
Drop down transaction costs	**-**	(18)	**-**	(20)
Earnings/(loss) before interest and income taxes	**(48)**	65	**173**	(376)

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 three and six months ended June 30, 2016 was a realized loss of $64 million and $151 million, respectively, compared with $48 million and $99 million for the corresponding 2015 periods. The realized loss 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 dollar 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 the three and six months ended June 30, 2016 was US$261 million and US$522 million, respectively, compared with US$238 million and US$476 million for the three and six months ended June 30, 2015. The average price to sell United States dollars for Canadian dollars for the three and six-month periods ended June 30, 2016 was $1.04, compared with $1.03 for the three and six-month periods ended June 30, 2015. The Exchange Rate for the three and six months ended June 30, 2016 was $1.29 and $1.33, compared with $1.23 and $1.24 for the three and six months ended June 30, 2015. As the hedged rate was lower than the Exchange Rate in each of the three and six-month periods in 2016 and 2015, the Company recognized a realized hedge loss in each of these periods. The realized hedge loss for both the three and six months ended June 30, 2016 was greater than the comparative 2015 periods due to a higher notional amount of derivatives and a greater unfavourable spread between the Exchange Rate and hedged 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 Exchange Rate of $1.29 and $1.33 for the three and six months ended June 30, 2016 which is reflected in the reported EBIT of the applicable business segments.

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.

LIQUIDITY AND CAPITAL RESOURCES

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

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

CAPITAL MARKET ACCESS

The Company and its self-funding subsidiaries ensure ready access to capital markets through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. As discussed under *Recent Developments Common Share Issuances*, the Company and ENF have raised $2.3 billion and $0.6 billion, respectively, through public offerings since the beginning of 2016.

Bank Credit and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, Enbridge maintains ready access to funds through committed bank credit facilities and it actively manages its bank funding sources to optimize pricing and other terms. The following table provides details of the Company s committed credit facilities as at June 30, 2016 and December 31, 2015.

		June 30, 2016			December 31, 2015
	Maturity Dates	Total Facilities	Draws1	Available	Total Facilities
(millions of Canadian dollars)					
Enbridge	2017-2020	**8,130**	**5,153**	**2,977**	6,988
Enbridge (U.S.) Inc.	2017				