ENBRIDGE

ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

March 31, 2015

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FOR THE THREE MONTHS ENDED MARCH 31, 2015

This Management's Discussion and Analysis (MD&A) dated May 5, 2015 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 months ended March 31, 2015, prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP). It should also be read in conjunction with the audited consolidated financial statements and MD&A contained in the Company's Annual Report for the year ended December 31, 2014. 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.

CONSOLIDATED EARNINGS

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**(422)**	44
Gas Distribution	**139**	136
Gas Pipelines, Processing and Energy Services	**16**	191
Sponsored Investments	**131**	84
Corporate	**(247)**	(111)
Earnings/(loss) attributable to common shareholders from continuing operations	**(383)**	344
Discontinued operations - Gas Pipelines, Processing and Energy Services	**-**	46
Earnings/(loss) attributable to common shareholders	**(383)**	390
Earnings/(loss) per common share	**(0.46)**	0.48
Diluted earnings/(loss) per common share	**(0.46)**	0.47

Loss attributable to common shareholders was $383 million for the three months ended March 31, 2015, or a loss of $0.46 per common share, compared with earnings of $390 million, or $0.48 per common share, for the three months ended March 31, 2014. The Company delivered solid results from operations in the first quarter of 2015; however, the visibility and comparability of the operating results are impacted by a number of unusual, non-recurring or non-operating factors, the most significant of which is changes in unrealized derivative fair value gains and losses. The Company has a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price exposures. The changes in unrealized mark-to-market accounting impacts from this program create volatility in short-term earnings, but the Company believes that over the long-term it supports the reliable cash flows and dividend growth upon which the Company's investor value proposition is based.

Other factors impacting the comparability of period-over-period earnings included an out-of-period adjustment of $71 million recognized in the first quarter of 2015 in respect of an overstatement of deferred income tax expense in 2013 and 2014, as well as insurance recoveries of $9 million after-tax related to the Line 37 crude oil release, which occurred in June 2013.

FORWARD-LOOKING INFORMATION

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

Although Enbridge believes these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; expected exchange rates; inflation; interest rates; availability and price of labour and pipeline construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for the Company's projects; anticipated in-service dates; final approval of definitive transfer terms by Enbridge and Enbridge Income Fund Holdings Inc. (ENF) and Enbridge Income Fund (the Fund) with respect to the Canadian Restructuring Plan; receipt of all necessary shareholder and regulatory approvals that may be required for the Canadian Restructuring Plan; and weather. 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 earnings/(loss) or adjusted earnings/(loss) and associated per share amounts, the impact of the Canadian Restructuring Plan on Enbridge, the adjusted dividend payout policy or estimated future dividends. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated completion dates and expected capital expenditures include the following: the availability and price of labour and pipeline construction materials; the effects of inflation and foreign exchange rates on labour and material costs; the effects of interest rates on borrowing costs; the impact of weather; and customer and regulatory approvals on construction and in-service schedules.

Enbridge's forward-looking statements are subject to risks and uncertainties pertaining to the Canadian Restructuring Plan, revised dividend policy, adjusted earning guidance, operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law and tax rate increases, exchange rates, interest rates, commodity prices and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Company's other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and Enbridge's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Enbridge or persons acting on the Company's behalf, are expressly qualified in their entirety by these cautionary statements.

NON-GAAP MEASURES

This MD&A contains references to non-GAAP measures, including adjusted earnings/(loss), which represent earnings or loss attributable to common shareholders adjusted for unusual, non-recurring or non-operating factors on both a consolidated and segmented basis. These factors, referred to as adjusting items, are reconciled and discussed in the financial results sections for the affected business segments. Adjusting items referred to as 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. Management believes the presentation of non-GAAP measures such as adjusted earnings/(loss) provides useful information to investors and shareholders as it provides increased transparency and predictive value. Management uses adjusted earnings/(loss) to set targets, including setting the Company's dividend payout target, and to assess the performance of the Company. Adjusted earnings/(loss) and adjusted earnings/(loss) for each of the segments are not measures that have a standardized meaning prescribed by U.S. GAAP and are not considered GAAP measures; therefore, these measures may not be comparable with similar measures presented by other issuers. The table below summarizes the reconciliation of the GAAP and non-GAAP measures.

NON-GAAP RECONCILIATIONS

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Earnings/(loss) attributable to common shareholders	**(383)**	390
Adjusting items[1]:		
Changes in unrealized derivative fair value loss[2]	**977**	190
Make-up rights adjustments	**4**	2
Leak insurance recoveries	**(9)**	-
Colder than normal weather	**(33)**	(33)
Project development and transaction costs	**3**	-
Tax related adjustments	**(6)**	-
Out-of-period adjustment	**(71)**	-
Gains on sale of non-core assets and investment	**-**	(57)
Other	**(14)**	-
Adjusted earnings	**468**	492

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.

ADJUSTED EARNINGS

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars, except per share amounts)		
Liquids Pipelines	**192**	218
Gas Distribution	**106**	103
Gas Pipelines, Processing and Energy Services	**41**	59
Sponsored Investments	**127**	84
Corporate	**2**	28
Adjusted earnings	**468**	492
Adjusted earnings per common share	**0.56**	0.60

Adjusted earnings were $468 million, or $0.56 per common share, for the three months ended March 31, 2015 compared with $492 million, or $0.60 per common share, for the three months ended March 31, 2014.

The following factors impacted adjusted earnings:

- Within Liquids Pipelines, adjusted earnings decreased quarter-over-quarter due to lower contributions from Canadian Mainline and Southern Lights Pipeline. Canadian Mainline adjusted earnings reflected the positive effects of higher throughput, higher terminalling revenues, a favourable United States/Canada foreign exchange rate and lower income taxes. However, these positive factors were more than offset by a lower quarter-over-quarter Canadian Mainline International Joint Tariff (IJT) Residual Benchmark Toll, higher power costs associated with higher throughput and higher operating and administrative expense. Growing volumes on the system, together with the impact of a higher Canadian Mainline IJT Residual Benchmark Toll and applicable surcharges for system expansions as they come into service, including surcharges for the recently completed Edmonton to Hardisty Expansion, are expected to drive strong revenues and earnings growth over the balance of 2015. The majority of the economic benefit derived from Southern Lights Pipeline is now reflected in earnings from the Fund following the Fund's November 2014 subscription and purchase of Class A units of Enbridge subsidiaries, which provide the Fund a defined cash flow stream from Southern Lights Pipeline.
- Within Gas Distribution, Enbridge Gas Distribution Inc. (EGD) adjusted earnings decreased primarily due to the lower interim distribution rates applicable in the first quarter of 2015 compared with the interim rates applicable in the corresponding 2014 period. Any shortfall in revenues arising from the difference between interim and final 2015 rates will be adjusted during 2015 and will not have an impact on full year results, which are expected to be higher than the prior year. The decrease in EGD adjusted earnings was more than offset by the absence of a loss that Enbridge Gas New Brunswick Inc. (EGNB) incurred in 2014 under a contract to sell natural gas to the province of New Brunswick. Due to an abnormally cold winter in the first quarter of 2014, costs associated with the fulfilment of the contract were higher than the revenues received.
- Within Gas Pipelines, Processing and Energy Services, the decrease in adjusted earnings reflected the absence of earnings from Alliance Pipeline US, which was transferred to the Fund in November 2014, as well as lower earnings from Aux Sable due to lower fractionation margins. Partially offsetting the decrease in adjusted earnings was an increase in take-or-pay fees on the Company's investment in Cabin Gas Plant (Cabin).
- Within Sponsored Investments, adjusted earnings from Enbridge Energy Partners, L.P. (EEP) reflected higher throughput and tolls on EEP's major liquids pipelines, as well as contributions from new assets placed into service in 2014, the most prominent being the replacement and expansion of Line 6B. EEP adjusted earnings also reflected incremental earnings from the January 2, 2015 transfer of the remaining 66.7% interest in Alberta Clipper previously held by Enbridge. Higher contribution from EEP also reflected distributions from Class D units which were issued to Enbridge in July 2014 under an equity restructuring transaction and from Class E units which were issued in January 2015 in connection with the transfer of Alberta Clipper.
- Also within Sponsored Investments, the Fund first quarter adjusted earnings reflected the impact of the transfer of natural gas and diluent pipeline interests from Enbridge, partially offset by higher financing costs associated with the debt issued to partially finance this transfer and higher income taxes. Adjusted earnings were also positively impacted by higher preferred unit distributions received by Enbridge from the Fund.
- Within the Corporate segment, an increase in Other Corporate loss reflected higher preference share dividends from an increase in the number of preference shares in 2014 to fund the Company's growth capital program.

RECENT DEVELOPMENTS

CANADIAN RESTRUCTURING PLAN

On March 31, 2015, Enbridge announced that it had delivered a formal proposal to a committee of independent members of the boards of Enbridge Commercial Trust (ECT) and ENF to transfer Enbridge's Canadian Liquids Pipelines business, comprised of Enbridge Pipelines Inc. and Enbridge Pipelines (Athabasca) Inc., along with certain renewable energy assets, with a combined carrying value of approximately $17 billion and an associated secured growth capital program of approximately $15 billion, to the Fund (collectively, the Canadian Restructuring Plan). The formal proposal follows the Company's December 3, 2014 announcement of the proposed Canadian Restructuring Plan. The general terms and projected financial outcomes of the proposed transfer are substantially consistent with those originally described in that announcement and the MD&A for the year ended December 31, 2014.

Pursuant to the plan, ENF is expected to acquire an increasing interest in the transferred assets through investments in the equity of the Fund over a period of several years in amounts consistent with its equity funding capability. The Canadian Restructuring Plan was approved in principle by Enbridge's Board of Directors in December 2014, but remains subject to finalization of internal reorganization steps and a number of internal and external consents and approvals, including all necessary shareholder and regulatory approvals and final approval of definitive transfer terms by the Enbridge Board of Directors. The transfer also remains subject to approval by the boards of ECT and ENF, following a recommendation by a joint special committee. The joint special committee has been established and is comprised of independent directors of ENF and independent trustees of ECT and has engaged independent financial, technical and legal advisors to support its assessment of the proposed transfer. Assuming all necessary consents and approvals are obtained, the transfer and initial investment by ENF are targeted for completion by mid-2015. However, there can be no assurance that the planned restructuring will be completed in the manner contemplated, or at all, or that the current market conditions and Enbridge's future forecast, based on such market conditions, will not materially change.

Enbridge is also in the process of reviewing a potential United States restructuring plan which would involve the transfer of its United States liquids pipelines assets to EEP. This review has not yet progressed to a conclusion.

DIVIDENDS

In December 2014, the Company announced an increase in its targeted dividend payout range from 60% to 70% of adjusted earnings to 75% to 85% of adjusted earnings. Following that announcement, the Company increased its quarterly common share dividend by approximately 33% to $0.465 per share effective March 1, 2015.

LIQUIDS PIPELINES

Seaway Pipeline Regulatory Matter

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011. Initially, the Federal Energy Regulatory Commission (FERC) rejected the application in March 2012 and Seaway Pipeline appealed to the District of Columbia Circuit. In response, the FERC set the application for further proceedings and the appeal was stayed. Since the FERC had not issued a ruling on this application, Seaway Pipeline filed for initial rates in order to have rates in effect by the in-service date. The uncommitted rate on Seaway Pipeline was challenged by several shippers. During the evidentiary stage, FERC staff filed evidence stating that the committed and uncommitted rates are subject to review and adjustment. Seaway Pipeline filed a Petition for Declaratory Order (PDO) requesting the FERC confirm that it will honour and uphold existing contracts. The FERC issued a decision denying the PDO on procedural grounds but stated that it will uphold its longstanding policy of honouring contracts.

The FERC hearings concluded with all parties filing their respective briefs. In September 2013, a decision from the Administrative Law Judge (ALJ) was released finding that the committed and uncommitted rates on Seaway Pipeline should be reduced to reflect the ALJ's findings on the various cost of service inputs. Seaway Pipeline filed a brief with the FERC on October 15, 2013, challenging the ALJ's decision and asking for expedited ruling by the FERC on the committed rates. In February 2014, the FERC issued its decision upholding its policy to honour contracts and ordered the ALJ to revise her decision accordingly. On May 9, 2014, the ALJ issued an initial decision on remand reiterating her previous findings and did not change her decision. Briefings have concluded and the full record was sent to the FERC for its final decision, which is still pending.

In relation to the original market-based rate application, the FERC issued its decision rejecting Seaway Pipeline's application for market-based rates in February 2014 and announced a new methodology for determining whether a pipeline has market power and invited Seaway Pipeline to refile its market-based rate application consistent with the new policy. In December 2014, Seaway Pipeline filed a new market-based rate application. The FERC noticed the application in the Federal Register and in response, several parties filed comments in opposition to the application alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. No procedural schedule has been set as of this date.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Aux Sable Environmental Protection Agency Matter

In September 2014, Aux Sable received a Notice and Finding of Violation (NFOV) from the United States Environmental Protection Agency (EPA) for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable's Channahon, Illinois facility. As part of the ongoing process of responding to the September 2014 NFOV, Aux Sable discovered what it believes to be an exceedance of currently permitted limits for Volatile Organic Material. Aux Sable received a second NFOV from the EPA in April 2015 in connection with this potential exceedance. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. At this time, the Company is unable to reasonably estimate the financial impact, if any, which might result from discussions with the EPA.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

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

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the EPA (the Order) which required additional containment and active recovery of submerged oil relating to the Line 6B crude oil release. On February 12, 2015, the EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modifications and acknowledged that EEP had completed the dredging requirements of the Order. At this time, EEP has completed all of the SORA.

Regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). EEP is now working with the MDEQ who has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at March 31, 2015, EEP's total cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($193 million after-tax attributable to Enbridge).

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at March 31, 2015. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release. On February 20, 2015, Enbridge, EEP and their affiliates agreed to a consent order releasing the parties from any claims, liability or penalties.

Insurance Recoveries

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

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

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

Enbridge has renewed its comprehensive property and liability insurance programs, which are effective May 1, 2015 through April 30, 2016 with a liability program aggregate limit of US$860 million, which includes sudden and accidental pollution liability. In the unlikely event 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. Approximately six actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. 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.

As at March 31, 2015, included in EEP's estimated costs related to the Line 6B crude oil release is US$48 million in fines and penalties. Of this amount, US$40 million related to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$40 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures, when combined with any fine or penalty, could be material. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

EEP Common Unit Issuance

In March 2015, EEP completed the issuance of eight million Class A Common Units for gross proceeds of approximately US$294 million before underwriting discounts and commissions and offering expenses. Enbridge did not participate in the issuance; however, the Company made a capital contribution of US$6 million to maintain its 2% general partner interest in EEP. EEP expects to use the proceeds from the offering to fund a portion of its capital expansion projects, for general partnership purposes or any combination of such purposes.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

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

		Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1.	Eastern Access Line 9 Reversal and Expansion	$0.7 billion	$0.7 billion	2013-2015 (in phases)	Substantially Complete
2.	Canadian Mainline Expansion	$0.7 billion	$0.5 billion	2015	Under construction
3.	Surmont Phase 2 Expansion	$0.3 billion	$0.3 billion	2014-2015 (in phases)	Complete
4.	Canadian Mainline System Terminal Flexibility and Connectivity	$0.7 billion	$0.5 billion	2013-2015 (in phases)	Under construction
5.	Sunday Creek Terminal Expansion	$0.2 billion	$0.2 billion	2015	Under construction
6.	Woodland Pipeline Extension	$0.7 billion	$0.6 billion	2015	Under construction
7.	Edmonton to Hardisty Expansion	$1.8 billion	$1.2 billion	2015 (in phases)	Under construction
8.	Southern Access Extension	US$0.6 billion	US$0.2 billion	2015	Under construction
9.	AOC Hangingstone Lateral	$0.2 billion	$0.1 billion	2015	Under construction
10.	JACOS Hangingstone Project	$0.2 billion	No significant expenditures to date	2016	Pre-construction
11.	Regional Oil Sands Optimization Project	$2.6 billion	$1.3 billion	2017	Under construction
12.	Norlite Pipeline System[3]	$1.3 billion	No significant expenditures to date	2017	Pre-construction
13.	Canadian Line 3 Replacement Program	$4.9 billion	$0.5 billion	2017	Pre-construction

	Estimated Capital Cost[1]	Expenditures to Date[2]	Expected In-Service Date	Status
GAS DISTRIBUTION				
14. Greater Toronto Area Project	$0.8 billion	$0.3 billion	2015	Under construction
GAS PIPELINES, PROCESSING AND ENERGY SERVICES				
15. Keechi Wind Project	US$0.2 billion	US$0.2 billion	2015	Complete
16. Walker Ridge Gas Gathering System	US$0.4 billion	US$0.3 billion	2014-2015 (in phases)	Under construction
17. Big Foot Oil Pipeline	US$0.2 billion	US$0.2 billion	2015	Under construction
18. Aux Sable Extraction Plant Expansion	US$0.1 billion	No significant expenditures to date	2016	Pre-construction
19. Heidelberg Oil Pipeline	US$0.1 billion	US$0.1 billion	2016	Under construction
20. Stampede Oil Pipeline	US$0.2 billion	No significant expenditures to date	2018	Pre-construction
SPONSORED INVESTMENTS				
21. EEP - Eastern Access[4]	US$2.7 billion	US$2.2 billion	2013-2016 (in phases)	Under construction
22. EEP - Lakehead System Mainline Expansion[4]	US$2.3 billion	US$1.3 billion	2014-2017 (in phases)	Under construction
23. EEP - Beckville Cryogenic Processing Facility	US$0.2 billion	US$0.1 billion	2015	Under construction
24. EEP - Eaglebine Gathering	US$0.2 billion	US$0.1 billion	2015-2016 (in phases)	Under construction
25. EEP - Sandpiper Project[5]	US$2.6 billion	US$0.6 billion	2017	Pre-construction
26. EEP - U.S. Line 3 Replacement Program	US$2.6 billion	US$0.2 billion	2017	Pre-construction

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect Enbridge's share of joint venture projects.
2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to March 31, 2015.
3 Enbridge will construct and operate the Norlite Pipeline System. Keyera Corp. will fund 30% of the project.
4 The Eastern Access and Lakehead System Mainline Expansion projects are funded 75% by Enbridge and 25% by EEP.
5 Enbridge will construct and operate the Sandpiper Project. Marathon Petroleum Corporation will fund 37.5% of the project.

LIQUIDS PIPELINES

Eastern Access

The Eastern Access initiative includes 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. Projects being undertaken by Enbridge include a reversal of Line 9A and expansion of the Toledo Pipeline, both completed in 2013, as well as the reversal of Line 9B and expansion of Line 9 (together, Line 9). For discussion on EEP's portion of Eastern Access, refer to *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Eastern Access*.

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

The Line 9B Reversal and Line 9 Capacity Expansion projects were approved by the National Energy Board (NEB) in March 2014 subject to 30 conditions. In October 2014, the NEB requested additional information regarding one of the conditions imposed on the Line 9B Reversal and Line 9 Capacity Expansion Project. On October 23, 2014, Enbridge responded to the NEB describing the Company's rigorous approach to risk management and isolation valve placement. On February 6, 2015, the NEB approved Conditions 16 and 18, the two conditions in the NEB's order requiring approval, and the Company filed for a Leave to Open, which is a prerequisite to allowing the operation of the project. Subject to NEB approval of the Leave to Open application, Enbridge expects to place the Line 9B Reversal and Line 9 Capacity Expansion Project into service in the second quarter of 2015. In its February approval, the NEB also imposed additional obligations on Enbridge that direct the Company to take a "life-cycle" approach to water crossings and valves, requiring the Company to perform ongoing analysis to ensure optimal protection of the area's water resources.

The conditions previously imposed by the NEB, including costs associated with additional NEB mandated integrity testing, increased the total expected cost of the projects to $0.7 billion, inclusive of costs related to the previously mentioned Line 9A reversal. Enbridge has reached an agreement with shippers to recover a portion of the incremental cost of additional valves ordered by the NEB through a toll surcharge. Total expenditures to date on the Line 9A and Line 9B projects are approximately $0.7 billion.

On July 31, 2014, Enbridge filed an application for tolls on Line 9. After complaints from shippers on Line 9 were filed with the NEB with respect to the inclusion of mainline surcharges in the Line 9 toll, Enbridge requested that the NEB approve the tolls on an interim basis to allow for time to engage shippers in further discussions to attempt to resolve the outstanding issues. The NEB established interim tolls, which remain in effect, and in late 2014, Enbridge and shippers filed letters with the NEB requesting that it establish a process to consider the issues. The NEB has set a written hearing with oral reply argument to be heard on May 28, 2015.

Canadian Mainline Expansion
Enbridge is undertaking an expansion of the Alberta Clipper line between Hardisty, Alberta and the Canada/United States border near Gretna, Manitoba. The scope of the project consists of two phases that involve the addition of pumping horsepower to raise the capacity of the Alberta Clipper line from 450,000 bpd to 800,000 bpd. The initial phase to increase capacity from 450,000 bpd to 570,000 bpd was completed in the third quarter of 2014 at an estimated capital cost of approximately $0.2 billion. The second phase to increase capacity from 570,000 bpd to 800,000 bpd is expected to be completed in the third quarter of 2015 at an expected cost of approximately $0.5 billion. The estimated cost of the entire expansion is approximately $0.7 billion, with expenditures to date of approximately $0.5 billion. Receipt of the applicable regulatory approvals on EEP's portion of the mainline system expansion has been delayed. EEP continues to work with regulatory authorities; however, the timing of the Federal regulatory approval cannot be determined at this time. A number of temporary system optimization actions have been undertaken to substantially mitigate any impact on throughput associated with any delays in obtaining applicable regulatory approvals. See *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – Lakehead System Mainline Expansion*.

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

Canadian Mainline System Terminal Flexibility and Connectivity
As part of the Light Oil Market Access Program initiative, the Company is undertaking the Canadian Mainline System Terminal Flexibility and Connectivity project in order to accommodate additional light oil volumes and enhance the operational flexibility of the Canadian mainline terminals. The modifications are

comprised of upgrading existing booster pumps, installing additional booster pumps and adding new tank line connections. These projects have varying completion dates from 2013 through the second quarter of 2015. The cost of the project is expected to be approximately $0.7 billion, with expenditures to date of approximately $0.5 billion.

Sunday Creek Terminal Expansion
In 2014, the Company announced it will construct additional facilities at its existing Sunday Creek Terminal, located in the Christina Lake area of northern Alberta, to support production growth from the Christina Lake oil sands project operated by Cenovus Energy Inc. and jointly owned with ConocoPhillips. The expansion includes development of a new site adjacent to the existing terminal, construction of a new 350,000 barrel tank with associated piping, pumps and measurement equipment, as well as civil construction work for a future tank. The estimated cost for the expansion is approximately $0.2 billion, with expenditures to date of approximately $0.2 billion and a targeted in-service date in the third quarter of 2015.

Woodland Pipeline Extension
The joint venture Woodland Pipeline Extension Project will extend the Woodland Pipeline south from Enbridge's Cheecham Terminal to its Edmonton Terminal. The extension is a proposed 388-kilometre (241-mile), 36-inch diameter pipeline with an initial capacity of 400,000 bpd, expandable to 800,000 bpd. Enbridge's share of the estimated capital cost of the project is now approximately $0.7 billion, with expenditures incurred to date of approximately $0.6 billion. The project has a target in-service date of the third quarter of 2015.

Edmonton to Hardisty Expansion
The Company is undertaking an expansion of the Canadian Mainline system between Edmonton, Alberta and Hardisty, Alberta. The expansion project includes 181 kilometres (112 miles) of new 36-inch diameter pipeline and will provide an initial capacity of approximately 570,000 bpd, expandable to 800,000 bpd. The new line generally follows the same route as Enbridge's existing Line 4 pipeline. Also included in the project scope are connections into existing infrastructure at the Hardisty Terminal and new terminal facilities in Edmonton, Alberta which include five new 500,000 barrel tanks. The new pipeline was placed into service in April 2015, with additional tankage requirements expected to be completed by the third quarter of 2015. The total cost of the project is expected to be approximately $1.8 billion, with expenditures to date of approximately $1.2 billion.

Southern Access Extension
The Southern Access Extension joint venture involves the construction of a new 265-kilometre (165-mile), 24-inch diameter crude oil pipeline from Flanagan, Illinois to Patoka, Illinois, for an initial capacity of approximately 300,000 bpd, as well as additional tankage and two new pump stations. Subject to regulatory and other approvals, the project is expected to be placed into service in the fourth quarter of 2015. Enbridge's share of the estimated capital cost is expected to be approximately US$0.6 billion, with expenditures to date of approximately US$0.2 billion.

AOC Hangingstone Lateral
In 2013, the Company entered into an agreement with Athabasca Oil Corporation (AOC) to provide pipeline and terminalling services to the proposed AOC Hangingstone Oil Sands Project (AOC Hangingstone) in Alberta. Phase I of the project will involve the construction of a new 49-kilometre (31-mile), 16-inch diameter pipeline from the AOC Hangingstone project site to Enbridge's existing Cheecham Terminal and related facility modifications at Cheecham, Alberta. Phase I of the project will provide an initial capacity of 16,000 bpd and is expected to be placed into service in the fourth quarter of 2015 at an estimated cost of approximately $0.2 billion. Expenditures to date on the project are approximately $0.1 billion. Phase 2 of the project, which is subject to commercial approval, would provide up to an additional 60,000 bpd for a total capacity of 76,000 bpd.

JACOS Hangingstone Project
Enbridge will undertake the construction of facilities and provide transportation services to the Japan Canada Oil Sands Limited (JACOS) Hangingstone Oil Sands Project (JACOS Hangingstone). JACOS

and Nexen Energy ULC, a wholly-owned subsidiary of China National Offshore Oil Corporation Limited, are partners in the project which is operated by JACOS. Enbridge plans to construct a new 53-kilometre (33-mile), 12-inch lateral pipeline to connect the JACOS Hangingstone project site to Enbridge's existing Cheecham Terminal. The project, which will provide capacity of 40,000 bpd and is expected to enter service in 2016, is estimated to cost approximately $0.2 billion.

Regional Oil Sands Optimization Project

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

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

The definitive cost estimate of the Wood Buffalo Extension was finalized at approximately $1.8 billion before optimization. As a result of the optimization, the cost estimate to complete the integrated Wood Buffalo Extension and Athabasca Pipeline Twin projects is expected to decrease from approximately $3.0 billion to approximately $2.6 billion. Expenditures on the joint projects to date are approximately $1.3 billion.

Subject to regulatory and other approvals, the integrated Wood Buffalo Extension and Athabasca Pipeline Twin will transport diluted bitumen from the proposed Fort Hills Partners' oil sands project (Fort Hills Project) in northeastern Alberta, as well as from oil sands production from Suncor Energy Oil Sands Limited Partnership (Suncor Partnership) in the Athabasca region. Along with the Norlite Pipeline System (Norlite), discussed below, the Wood Buffalo Extension and the Athabasca Pipeline Twin will be the conduit to ship diluent to, and blended bitumen from, the Fort Hills Project which has an expected 2017 in-service date.

Norlite Pipeline System

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

Canadian 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 Canadian portion of the Line 3 Replacement Program

(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. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the overall system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system's overall western Canada export capacity.

Subject to regulatory and other approvals, the Canadian L3R Program is targeted to be completed in late 2017. Following the completion of a definitive cost estimate in the second quarter of 2014, the estimated capital cost of the Canadian L3R Program is approximately $4.9 billion, with expenditures to date of approximately $0.5 billion. Costs of the Canadian L3R Program will be recovered through a 15-year toll surcharge mechanism under the Competitive Toll Settlement (CTS). For discussion on EEP's portion of the L3R Program, refer to *Growth Projects – Commercially Secured Projects – Sponsored Investments – Enbridge Energy Partners, L.P. – United States Line 3 Replacement Program*.

GAS DISTRIBUTION

Greater Toronto Area Project

EGD is undertaking the expansion of its natural gas distribution system in the Greater Toronto Area (GTA) to meet the demands of growth and to continue the safe and reliable delivery of natural gas to current and future customers. The GTA project involves the construction of two new segments of pipeline, a 27-kilometre (17-mile), 42-inch diameter pipeline and a 23-kilometre (14-mile), 36-inch diameter pipeline in Toronto, Ontario, as well as related facilities to upgrade the existing distribution system that delivers natural gas to several municipalities in Ontario. Construction began in January 2015 and completion of the project is expected in the fourth quarter of 2015 at an estimated cost of approximately $0.8 billion, with expenditures to date of approximately $0.3 billion.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

Keechi Wind Project

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

Walker Ridge Gas Gathering System

The Company has agreements with Chevron USA Inc. (Chevron) and Union Oil Company of California to expand its central Gulf of Mexico offshore pipeline system. Under the terms of the agreements, Enbridge is constructing and will own and operate the Walker Ridge Gas Gathering System (WRGGS) to provide natural gas gathering services to the Jack St. Malo and Big Foot ultra-deep water developments. The WRGGS includes 274 kilometres (170 miles) of 8-inch or 10-inch diameter pipeline at depths of up to approximately 2,150 metres (7,000 feet), with capacity of 100 million cubic feet per day (mmcf/d). The Jack St. Malo portion of the WRGGS was placed into service in December 2014 and the Big Foot Oil Pipeline (Big Foot Pipeline) portion is expected to be placed into service in the third quarter of 2015. The total WRGGS project is expected to cost approximately US$0.4 billion, with expenditures to date of approximately US$0.3 billion.

Big Foot Oil Pipeline

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

Aux Sable Extraction Plant Expansion
In 2014, the Company approved the expansion of fractionation capacity and related facilities at its Aux Sable Extraction Plant located in Channahon, Illinois. The expansion will facilitate 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 be placed into service in 2016, with Enbridge's share of the project cost being approximately US$0.1 billion.

Heidelberg Oil Pipeline
The Company will construct, own and operate a crude oil pipeline in the Gulf of Mexico to connect the proposed Heidelberg development, operated by Anadarko Petroleum Corporation, to an existing third-party system. Heidelberg Oil Pipeline (Heidelberg Pipeline), a 58-kilometre (36-mile), 20-inch diameter pipeline with capacity of 100,000 bpd, will originate in Green Canyon Block 860, approximately 320 kilometres (200 miles) southwest of New Orleans, Louisiana and in an estimated 1,600 metres (5,300 feet) of water. Heidelberg Pipeline is expected to be operational in 2016 at an approximate cost of US$0.1 billion, with expenditures to date of approximately US$0.1 billion.

Stampede Oil Pipeline
In January 2015, Enbridge announced that it will build, own and operate a crude oil pipeline in the Gulf of Mexico to connect the planned Stampede development, which is operated by Hess Corporation, to an existing third-party pipeline system. The Stampede Oil Pipeline (Stampede Pipeline), a 26-kilometre (16-mile), 18-inch diameter pipeline with capacity of approximately 100,000 bpd will originate in Green Canyon Block 468, approximately 350 kilometres (220 miles) southwest of New Orleans, Louisiana at an estimated depth of 1,200 metres (3,500 feet). Stampede Pipeline is expected to be completed at an approximate cost of US$0.2 billion and is expected to be placed into service in 2018.

SPONSORED INVESTMENTS – ENBRIDGE ENERGY PARTNERS, L.P.
Eastern Access
The Eastern Access initiative includes 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. Projects undertaken by EEP include an expansion of Line 5 and of the United States mainline involving the Spearhead North Pipeline (Line 62), both completed in 2013, and replacement of additional segments of Line 6B, completed in 2014. The cost of these completed projects was approximately US$2.4 billion. For discussion on Enbridge's portion of Eastern Access, refer to *Growth Projects – Commercially Secured Projects – Liquids Pipelines – Eastern Access*.

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

The total estimated cost of the projects being undertaken by EEP as part of the Eastern Access initiative, including the Line 6B capacity expansion project, is approximately US$2.7 billion, with expenditures to date of approximately US$2.2 billion. The Eastern Access projects undertaken by EEP are being funded 75% by Enbridge and 25% by EEP. Within one year of the final in-service date of the collective projects, EEP will have the option to increase its economic interest held at that time by up to an additional 15%.

Lakehead System Mainline Expansion
The Lakehead System Mainline Expansion includes several projects to expand capacity of the Lakehead System mainline between its origin at the Canada/United States border, near Neche, North Dakota, to Flanagan, Illinois. These projects are in addition to expansions of the Lakehead System mainline being

undertaken as part of the Eastern Access initiative and include the expansion of Alberta Clipper (Line 67) and Southern Access (Line 61) and the construction of the Spearhead North Twin (Line 78).

The current scope of the Alberta Clipper expansion between the border and Superior, Wisconsin consists of two phases. The initial phase included increasing capacity from 450,000 bpd to 570,000 bpd at an estimated capital cost of approximately US$0.2 billion. The second phase of the expansion will increase capacity from 570,000 bpd to 800,000 bpd at an estimated capital cost of approximately US$0.2 billion. The initial phase was completed in the third quarter of 2014 and the second phase is expected to be completed in the third quarter of 2015. Both phases of the Alberta Clipper expansion require only the addition of pumping horsepower with no pipeline construction and are subject to regulatory and other approvals, including an amendment to the current Presidential border crossing permit to allow for operation of Line 67 at its currently planned operating capacity of 800,000 bpd. EEP continues to work with regulatory authorities; however, the timing of the Federal regulatory approval for the expansion to 800,000 bpd 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 applicable regulatory approvals.

In November 2014, several environmental and Native American groups filed a complaint in the United States District Court in Minnesota against the United States Department of State (DOS). The Complaint alleges, among other things, that the DOS is in violation of the United States' National Environmental Policy Act by acquiescing in Enbridge’s use of permitted cross border capacity on other pipelines to achieve the transportation of amounts in excess of Alberta Clipper’s current permitted capacity while the review and approval of Enbridge’s application to the DOS to increase Alberta Clipper’s permitted cross border capacity is still pending. Enbridge has moved to intervene in the case and a decision at the trial level is not expected before the fourth quarter of 2015.

The current scope of the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois also consists of two phases. Both phases of the Southern Access expansion require only the addition of pumping horsepower with no pipeline construction. The initial phase to increase the capacity from 400,000 bpd to 560,000 bpd was completed in August 2014 at an estimated capital cost of approximately US$0.2 billion. EEP also plans to undertake a further expansion of the Southern Access line between Superior, Wisconsin and Flanagan, Illinois to increase capacity from 560,000 bpd to 1,200,000 bpd and add crude oil tankage at new and existing sites. The pipeline expansion will be split into two tranches. The first tranche will expand the pipeline capacity to 800,000 bpd at an estimated capital cost of approximately US$0.4 billion and is expected to be in service in the second quarter of 2015. Additional tankage is expected to cost approximately US$0.4 billion and will be completed on various dates beginning in the third quarter of 2015 through the second quarter of 2016. The second tranche, which remains subject to regulatory and other approvals, will expand the pipeline capacity to 1,200,000 bpd at an estimated capital cost of approximately US$0.4 billion and is expected to be in service in 2017. The Company, in conjunction with shippers, decided to delay the in-service date of the final tranche of the Line 61 expansion to align more closely with the currently anticipated in-service date for the Sandpiper Project (Sandpiper), which will drive the need for additional downstream capacity on the Lakehead System.

On April 17, 2015, EEP filed an amended tariff with the FERC to provide shippers with optional in-transit merchant storage service. The in-transit merchant storage service will provide shippers the ability to off-load barrels in-transit at Flanagan, Illinois or Superior, Wisconsin, direct them into temporary storage and later return them to the Lakehead System for delivery to their ultimate destinations. This service will be included in the applicable tariff rate from the initial origin point to the ultimate delivery point.

As part of the Light Oil Market Access Program, EEP also plans to expand the capacity of the Lakehead System between Flanagan, Illinois and Griffith, Indiana. This section of the Lakehead System will be expanded by constructing a 127-kilometre (79-mile), 36-inch diameter twin of the existing Spearhead North Pipeline (Line 62). The project is expected to be completed at an estimated cost of approximately US$0.5 billion. Subject to regulatory and other approvals, the new line will have an initial capacity of 570,000 bpd and is expected to be placed into service in the third quarter of 2015.

The projects collectively referred to as the Lakehead System Mainline Expansion are expected to cost approximately US$2.3 billion, with expenditures incurred to date of approximately US$1.3 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. 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%.

Beckville Cryogenic Processing Facility

EEP and its partially-owned subsidiary, Midcoast Energy Partners, L.P. (MEP), are constructing a cryogenic natural gas processing plant near Beckville (the Beckville Plant) in Panola County, Texas. The Beckville Plant will offer incremental processing capacity for existing and future customers in the 10-county Cotton Valley shale region, where the East Texas system is located. The Beckville Plant has a planned natural gas processing capability of 150 mmcf/d and is also expected to produce 8,500 bpd of NGL. The Beckville Plant is now expected to be placed into service in the second quarter of 2015 at an estimated cost of approximately US$0.2 billion. Expenditures incurred to date are approximately US$0.1 billion.

Eaglebine Gathering

In February 2015, EEP and MEP announced they are entering into the emerging Eaglebine shale play in East Texas through two transactions totalling approximately US$0.2 billion. EEP and MEP have commenced construction of a lateral and associated facilities that will create gathering capacity of over 50 mmcf/d for rich natural gas to be delivered from Eaglebine production areas to their complex of cryogenic processing facilities in East Texas. The initial facilities are projected to be placed into service by late 2015, with the lateral expected to be in service by mid-2016. MEP also acquired New Gulf Resources, LLC's midstream business in Leon, Madison and Grimes Counties, Texas. The acquisition consists of a natural gas gathering system that is currently in operation. Expenditures incurred to date are approximately US$0.1 billion.

Sandpiper Project

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. Sandpiper is expected to cost approximately US$2.6 billion, with expenditures incurred to date of approximately US$0.6 billion.

EEP is in the process of obtaining the appropriate construction permits within the state of Minnesota for Sandpiper. The permits require both a Certificate of Need and an approval of the pipeline's route (Route Permit) from the Minnesota Public Utilities Commission (MNPUC). In April 2015, the ALJ recommended that the MNPUC grant approval of the Certificate of Need based on evidence provided by Enbridge that the need for the system has been demonstrated. The ALJ also recommended that no alternative routes to that proposed by Enbridge should be considered in subsequent Route Permit process. The MNPUC is expected to take the ALJ's recommendation into account and make a decision on the Certificate of Need in the third quarter of 2015. A separate MNPUC review of the proposed pipeline route will follow. Subject to regulatory and other approvals, particularly in the State of Minnesota, the expected in-service date for Sandpiper is 2017.

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

United States Line 3 Replacement Program
In 2014, Enbridge and EEP jointly announced that shipper support was received for investment in the L3R Program. EEP will undertake the United States portion of the Line 3 Replacement Program (U.S. L3R Program) which will complement existing integrity programs by replacing approximately 576 kilometres (358 miles) of the remaining line segments of the existing Line 3 pipeline between Neche, North Dakota and Superior, Wisconsin. While the L3R Program will not provide an increase in the overall capacity of the mainline system, it will support the safety and operational reliability of the overall system, enhance flexibility and allow the Company to optimize throughput. The L3R Program is expected to achieve an equivalent 34-inch diameter pipeline capacity of approximately 760,000 bpd, which will enhance the flexibility and reliability of the Enbridge mainline system's overall western Canada export capacity.

Subject to regulatory and other approvals, the U.S. L3R Program is targeted to be completed in late 2017 at an estimated capital cost of approximately US$2.6 billion, with expenditures to date of approximately US$0.2 billion. 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.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by the Company, but have not yet met Enbridge's criteria to be classified as commercially secured. The Company also has significant additional attractive projects under development that have not yet progressed to the point of public announcement. In its long-term funding plans, the Company makes full provision for all commercially secured projects and makes provision for projects under development based on an assessment of the aggregate securement success anticipated. Actual securement success achieved could exceed or fall short of the anticipated level.

LIQUIDS PIPELINES
Northern Gateway Project
The 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 approved Northern Gateway, subject to 209 conditions. The Company continues to work closely with its customers in advancing this project to open West Coast market access and is making progress in fulfilling the conditions and building relationships and trust with communities and Aboriginal groups along the proposed route.

Nine applications to the Federal Court of Appeal (Federal Court) for leave for judicial review of the Order in Council have been filed pursuant to section 55 of the NEB Act. The applicants make two basic arguments in seeking leave. First, they argue that the report and the Order in Council contain evidentiary gaps or gaps in reasoning. Second, they allege that the Crown has failed to discharge its constitutional duty to consult and, if appropriate, accommodate the Aboriginal applicants.

On September 26, 2014, the Federal Court granted leave to all nine applications and on December 17, 2014, the Federal Court issued a decision accepting the request by all parties to consolidate the nine applications into a single proceeding (the Application) and stated that delays in the hearing of the

Application should be minimized. The Federal Court then set a schedule which would culminate with the filing of the Appellants' Memoranda of Fact and Law by May 22, 2015 and the Respondents' Memoranda by June 23, 2015. Based on this schedule, Northern Gateway expects that the hearing on the Application will occur in the fall of 2015. Depending on the outcome of these proceedings, which is anticipated late 2015, an application for Leave to Appeal to the Supreme Court of Canada is a possibility.

The Company has reviewed an updated cost estimate of Northern Gateway based on a 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, which reflected a preliminary estimate prepared in 2004 and escalated to 2010. The drivers behind this substantial increase include the significant costs associated with escalation of labour and construction costs, satisfying the 209 conditions imposed in the Governor in Council approval, a larger portion of high cost pipeline terrain, more extensive terminal site rock excavations and a delayed anticipated in-service date. The updated cost estimate is currently being assessed and refined by Northern Gateway and the potential shippers. Expenditures to date, which relate primarily to the regulatory process, are approximately $0.5 billion, of which approximately half is being funded by potential shippers on Northern Gateway.

Subject to continued commercial support, receipt of regulatory and other approvals and adequately addressing landowner and local community concerns (including those of Aboriginal communities), the Company estimates that Northern Gateway could be in service in 2019 at the earliest. The timing and outcome of judicial reviews could also impact the start of construction or other project activities, which may lead to a delay in the start of operations beyond the current forecast.

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 Joint Review Panel (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 http://www.gatewayfacts.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

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Canadian Mainline	**125**	141
Regional Oil Sands System	**48**	42
Seaway and Flanagan South Pipelines	**10**	10
Spearhead Pipeline	**6**	9
Southern Lights Pipeline	**2**	12
Feeder Pipelines and Other	**1**	4
Adjusted earnings	**192**	218
Canadian Mainline - changes in unrealized derivative fair value loss	**(616)**	(172)
Canadian Mainline - Line 9B costs incurred during reversal	**(2)**	-
Regional Oil Sands System - leak insurance recoveries	**9**	-
Regional Oil Sands System - make-up rights adjustment	**4**	(2)
Seaway and Flanagan South Pipelines - make-up rights adjustment	**(5)**	-
Spearhead Pipeline - make-up rights adjustment	**(1)**	-
Feeder Pipelines and Other - make-up rights adjustment	**(1)**	-
Feeder Pipelines and Other - project development costs	**(2)**	-
Earnings/(loss) attributable to common shareholders	**(422)**	44

Liquids Pipelines earnings/(loss) were impacted by the following adjusting items:

- Canadian Mainline loss for each period reflected changes in unrealized fair value losses on derivative financial instruments used to risk manage exposures inherent within the CTS, namely foreign exchange, power cost variability and allowance oil commodity prices.
- Canadian Mainline loss for the first quarter of 2015 included depreciation and interest expenses charged to Line 9B while it is idled and undergoing a reversal as part of the Company's Eastern Access initiative.
- Regional Oil Sands System earnings for the first quarter of 2015 included insurance recoveries associated with the Line 37 crude oil release, which occurred in June 2013.
- Feeder Pipelines and Other loss for the first quarter of 2015 included certain business development costs related to Northern Gateway that are anticipated to be recovered over the life of the project.

Canadian Mainline

Canadian Mainline adjusted earnings decreased in the first quarter of 2015 compared with the corresponding 2014 first quarter. Positively impacting adjusted earnings was higher throughput from strong oil sands production combined with strong refinery demand in the midwest market partly due to a start-up of a midwest refinery's conversion to heavy oil processing in the second quarter of 2014. Higher throughput was also achieved from continued efforts by the Company to optimize capacity utilization and to enhance scheduling efficiency with shippers. Other factors contributing to an increase in adjusted earnings included higher terminalling revenues and the impact of a stronger United States dollar compared with the Canadian dollar as the IJT Benchmark Toll and its components are set in United States dollars. Also positively impacting adjusted earnings were lower income tax expense, which reflected current income taxes only and were lower due to higher available tax deductions from a larger asset base and lower earnings on a period-over-period basis.

More than offsetting the positive factors noted above was a lower quarter-over-quarter Canadian Mainline IJT Residual Benchmark Toll. Changes in the Canadian Mainline IJT Residual Benchmark Toll are inversely related to the Lakehead System Toll, which was higher due to the recovery of incremental costs associated with EEP's growth projects. Effective April 1, 2015, the Canadian Mainline IJT Residual Benchmark Toll increased from US$1.53 per barrel to US$1.63 per barrel, following EEP's April 1, 2015 tariff filing for its Lakehead System. Growing volumes on the system, together with the impact of a higher

Canadian Mainline IJT Residual Benchmark Toll and applicable surcharges for system expansions as they come into service, including surcharges for the recently completed Edmonton to Hardisty Expansion, are expected to drive strong revenues and earnings growth over the balance of 2015. Other factors which contributed to lower adjusted earnings included higher power costs associated with higher throughput and higher operating and administrative expense to support increased business activities.

In the first quarter of 2015, the Company also commenced collecting, in its tolls, NEB mandated future abandonment costs from shippers. Approximately $9 million in revenues was recorded in the first quarter, but the amount was offset by a corresponding increase in operating and administrative expense. For further details, refer to *Critical Accounting Estimates*.

Supplemental information on Canadian Mainline adjusted earnings for the three months ended March 31, 2015 and 2014 is as follows:

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Revenues	**381**	373
Expenses		
Operating and administrative	**108**	83
Power	**50**	38
Depreciation and amortization	**67**	66
	225	187
	156	186
Other income	**4**	1
Interest expense	**(45)**	(40)
	115	147
Income taxes recovery/(expense)	**10**	(6)
Adjusted earnings	**125**	141
Effective United States to Canadian dollar exchange rate[1]	**1.08**	1.02

March 31,	**2015**	2014
(United States dollars per barrel)		
IJT Benchmark Toll[2]	**$4.02**	$3.98
Lakehead System Local Toll[3]	**$2.49**	$2.17
Canadian Mainline IJT Residual Benchmark Toll[4]	**$1.53**	$1.81

1 *Inclusive of realized gains and losses on foreign exchange derivative financial instruments.*

2 *The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2014, the IJT Benchmark Toll increased from US$3.98 to US$4.02.*

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

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

	Three months ended March 31,	
	2015	2014
Throughput volume[1] *(thousand barrels per day (kbpd))*	**2,210**	1,904

1 *Throughput volume, presented in kbpd, represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and Eastern Canada deliveries entering the mainline in Western Canada.*

Regional Oil Sands System
Regional Oil Sands System adjusted earnings increased for the three months ended March 31, 2015 compared with the first quarter of 2014. Adjusted earnings growth was driven by incremental earnings from the Norealis Pipeline which was completed in April 2014 and higher uncommitted volumes and capital expansion fee revenues on the Waupisoo Pipeline. Partially offsetting the positive adjusted earnings increase was a reduction in contracted volumes on the Athabasca Mainline, although it was mitigated in part by higher uncommitted volumes on this pipeline.

Seaway and Flanagan South Pipelines
Seaway and Flanagan South Pipelines adjusted earnings for the three months ended March 31, 2015 were comparable with the first quarter of 2014. During the first quarter of 2015, as a result of Canadian Mainline apportionment, throughput on Seaway and Flanagan South Pipelines was lower than the throughput committed on these pipelines. When committed shippers on Flanagan South are unable to fulfill their volume commitments due to apportionment, they are provided with temporary relief to make up those volumes during the course of their contracts or the apportioned volumes are added on to the end of the contract term. The impact of upstream apportionment is expected to be alleviated as the Company expands its mainline system in 2015 and through continued system optimization measures.

Spearhead Pipeline
Spearhead Pipeline adjusted earnings decreased in the first quarter of 2015 compared with the first quarter of 2014. Lower throughput due to upstream apportionment drove lower adjusted earnings, partially offset by a decrease in power cost associated with the lower throughput.

Southern Lights Pipeline
Southern Lights Pipeline earnings for the first quarter of 2015 decreased compared with the corresponding 2014 three-month period. The majority of the economic benefit derived from Southern Lights Pipeline is now reflected in earnings from the Fund following the Fund's November 2014 subscription and purchase of Class A units of Enbridge subsidiaries, which provide a defined cash flow stream from Southern Lights Pipeline.

Feeder Pipelines and Other
Feeder Pipelines and Other adjusted earnings for the three months ended March 31, 2015 decreased compared with the corresponding 2014 period. Higher business development costs not eligible for capitalization and lower average tolls on Olympic Pipeline were partially offset by higher earnings from Eddystone Rail Project completed in April 2014.

GAS DISTRIBUTION

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Enbridge Gas Distribution Inc. (EGD)	**85**	91
Other Gas Distribution and Storage	**21**	12
Adjusted earnings	**106**	103
EGD - colder than normal weather	**33**	33
Earnings attributable to common shareholders	**139**	136

EGD adjusted earnings decreased for the three months ended March 31, 2015 compared with the corresponding 2014 three-month period. The decrease in adjusted earnings was largely attributable to the timing of the approval of EGD's distribution rates by the Ontario Energy Board (OEB). In both the first quarters of 2015 and 2014, EGD operated under interim distribution rates. In the first quarter of 2015, the interim distribution rates were lower than the interim rates applicable in the comparative first quarter of 2014, partially offset by lower depreciation expense embedded within these distribution rates. The lower depreciation expense relates to applying the new approach for determining depreciation and future removal and site restoration reserves under the customized incentive rate plan approved by the OEB in the second half of 2014.

In April 2015, the OEB approved a comprehensive settlement proposal, inclusive of 2015 rates. The approved settlement allows for final 2015 rates to be implemented with the July 2015 Quarterly Rate Adjustment Mechanism, and will be effective January 1, 2015. EGD filed a draft rate order in April 2015 and anticipates approval by the OEB by the end of May 2015. EGD expects to collect and record the difference between the interim rates and applicable 2015 rates during 2015. The Company's policy is to account for regulatory decisions in the period in which they are received and will record the impact of the approved settlement prospectively. EGD's full year results are expected to be higher than the prior year.

Other Gas Distribution and Storage earnings for the first quarter of 2015 increased compared with the corresponding first quarter of 2014. The increase in earnings reflected the absence of a loss that EGNB incurred in 2014 under a contract to sell natural gas to the province of New Brunswick. Due to an abnormally cold winter in the first quarter of 2014, costs associated with the fulfilment of the contract were higher than the revenues received. Excluding the impact of the above noted contract which expired in October 2014, EGNB 2015 first quarter earnings increased slightly due to higher distribution revenues.

GAS PIPELINES, PROCESSING AND ENERGY SERVICES

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Aux Sable	**3**	7
Energy Services	**20**	24
Alliance Pipeline US	**-**	12
Vector Pipeline	**5**	6
Canadian Midstream	**10**	5
Enbridge Offshore Pipelines (Offshore)	**(1)**	4
Other	**4**	1
Adjusted earnings	**41**	59
Energy Services - changes in unrealized derivative fair value gains/(loss)	**(26)**	136
Offshore - gain on sale of non-core assets	**-**	43
Other - changes in unrealized derivative fair value gains/(loss)	**1**	(1)
Earnings attributable to common shareholders	**16**	237

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

- Energy Services earnings/(loss) for each period reflected changes in unrealized fair value gains and losses related to the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and the revaluation of inventory.
- Enbridge Offshore Pipelines (Offshore) earnings for the first quarter of 2014 included a gain from the disposal of non-core assets.
- Other earnings for each period reflected changes in unrealized fair value gains and losses on the long-term power price derivative contracts acquired to hedge expected revenues and cash flows from the Blackspring Ridge Wind Project (Blackspring Ridge).

Aux Sable earnings decreased, as anticipated, for the three months ended March 31, 2015 compared with the 2014 comparative period and reflected lower fractionation margins resulting from a weaker commodity price environment and the loss of a producer processing contract at the Palermo Conditioning Plant.

Energy Services operates a physical commodity marketing business which captures value from quality, time and location differentials when opportunities arise. To execute these strategies Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines and storage facilities. Energy Services adjusted earnings for the first quarter of

2015 decreased compared with the corresponding 2014 three month period. The decrease in adjusted earnings was attributable to narrowing location differentials and less favourable conditions in certain markets, particularly those accessed by committed transportation capacity, combined with associated unrecovered demand charges. Higher adjusted earnings in first quarter of 2014 also reflected the impact of more favourable natural gas differentials caused by abnormal winter weather conditions. Partially offsetting these negative effects was the absence of losses realized in the first quarter of 2014 on certain financial contracts intended to hedge the value of committed transportation capacity, but which were not effective in doing so. During the second quarter of 2014, the Company closed out a forward component of these derivative contracts which had been determined to be no longer effective. Also partially offsetting the decrease in adjusted earnings were more favourable conditions in certain markets that enable Energy Services to capture more profitable tank management arbitrage opportunities.

The absence of Alliance Pipeline US earnings in the first quarter of 2015 reflected the transfer of Alliance Pipeline US to the Fund in November 2014.

Vector Pipeline earnings were comparable between the first quarters of 2015 and 2014 and reflected the impact of increased demand for natural gas due to abnormal winter weather conditions.

Canadian Midstream earnings increased in the three months ended March 31, 2015 compared with the comparative 2014 period. Higher earnings reflected an increase in take-or-pay fees on the Company's investment in Cabin and the Pipestone and Sexsmith Sour Gas Gathering and Compression Facilities, as well as higher volumes at Pipestone.

Offshore adjusted earnings decreased in the first quarter of 2015 compared with the first quarter of 2014. The decrease in adjusted earnings reflected the absence of earnings from the disposals of non-core assets finalized in March 2014.

Adjusted earnings from Other for the first quarter of 2015 increased compared with the equivalent 2014 period and reflected contributions from new wind farms including Blackspring Ridge completed in May 2014 and the Magic Valley and Wildcat wind farms acquired at the end of 2014.

SPONSORED INVESTMENTS

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Enbridge Energy Partners, L.P. (EEP)	**62**	45
Enbridge Energy, Limited Partnership (EELP)	**20**	7
Enbridge Income Fund (the Fund)	**45**	32
Adjusted earnings	**127**	84
The Fund - make up rights adjustment	**(1)**	-
The Fund - changes in unrealized derivative fair value loss	**(11)**	-
The Fund - unrealized intercompany foreign exchange gains	**16**	-
Earnings attributable to common shareholders	**131**	84

EEP adjusted earnings increased in the first quarter of 2015 compared with the corresponding 2014 period. Adjusted earnings reflected similar trends experienced in the latter half of 2014 whereby earnings growth was driven by higher throughput and tolls in EEP's liquids business, as well as contributions from new assets placed into service in 2014, the most prominent being the replacement and expansion of Line 6B. In addition, EEP adjusted earnings reflected incremental earnings from the transfer on January 2, 2015 of the remaining 66.7% interest in Alberta Clipper previously held by Enbridge through Enbridge Energy, Limited Partnership (EELP). Partially offsetting the increase in adjusted earnings in EEP's liquids business were higher operating and administrative costs, incremental power costs associated with higher throughput and higher depreciation expense from an increased asset base. Also contributing to higher earnings in the first quarter of 2015 were distributions from Class D units which were issued to Enbridge in July 2014 under an equity restructuring transaction and from Class E units which were issued in January 2015 in connection with the transfer of Alberta Clipper. Finally, the first quarter of 2015 reflected lower volumes within EEP's natural gas and NGL businesses, which it holds directly and indirectly through its partially-owned subsidiary, MEP.

EELP earnings reflect Enbridge's interests in both the Eastern Access and Lakehead System Mainline expansion projects. Earnings from EELP increased due to contributions from assets recently placed into service, most notably the expansion of Line 6B completed in phases during 2014 as part of the Company's Eastern Access Program. Partially offsetting the increase in earnings was the absence of earnings from EELP's interest in Alberta Clipper which was transferred to EEP on January 2, 2015.

Adjusted earnings from the Fund increased for the three months ended March 31, 2015 compared with the corresponding 2014 first quarter. The increase in adjusted earnings reflected incremental earnings from natural gas and diluent pipeline interests transferred by Enbridge to the Fund in November 2014. Partially offsetting the increase in earnings were higher financing costs associated with debt raised to acquire the natural gas and diluent pipeline interests and higher income taxes. Finally, adjusted earnings were also positively impacted by higher preferred unit distributions received from the Fund.

CORPORATE

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Noverco Inc. (Noverco)	**30**	29
Other Corporate	**(28)**	(1)
Adjusted earnings	**2**	28
Noverco - changes in unrealized derivative fair value loss	**(3)**	(4)
Other Corporate - changes in unrealized derivative fair value loss	**(322)**	(149)
Other Corporate - deferred income tax out-of-period adjustment	**71**	-
Other Corporate - impact of tax rate changes	**6**	-
Other Corporate - drop down transaction costs	**(1)**	-
Other Corporate - gain on sale of investment	**-**	14
Loss attributable to common shareholders	**(247)**	(111)

Corporate loss was impacted by the following adjusting items:

- Other Corporate loss for each period included changes in the unrealized fair value losses on derivative financial instruments related to forward foreign exchange risk management positions.
- Other Corporate loss for the first quarter of 2015 included an out-of-period adjustment to reduce deferred income tax expense related to intercompany preferred dividends.

Other Corporate adjusted loss increased in the first quarter of 2015 compared with the first quarter of 2014 and reflected higher preference share dividends from an increase in the number of preference shares in 2014 to fund the Company's growth capital program.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to Enbridge's growth strategy, particularly in light of the record 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, Enbridge 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 through which it can monetize assets, with the objective of diversifying funding sources and maintaining access to low cost capital. During the first quarter of 2015, the Company completed the issuance of US$294 million Class A Common Units of its subsidiary EEP. Until the completion of the Canadian Restructuring Plan, targeted for mid-2015, the Company expects to rely less on public capital markets and more on available bank liquidity to meets its funding requirements.

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

		March 31, 2015			December 31, 2014
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**296**	**4**	300
Gas Distribution	2016-2019	**1,009**	**829**	**180**	1,008
Sponsored Investments	2016-2019	**4,907**	**3,483**	**1,424**	4,531
Corporate	2016-2019	**13,365**	**6,857**	**6,508**	12,772
Total committed credit facilities		**19,581**	**11,465**	**8,116**	18,611

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

In addition to the committed credit facilities noted above, the Company also has $385 million (2014 - $361 million) of uncommitted demand credit facilities, of which $103 million (2014 - $80 million) were unutilized as at March 31, 2015.

The Company's net available liquidity of $9,038 million as at March 31, 2015 was inclusive of $1,191 million of unrestricted cash and cash equivalents and net of bank indebtedness of $269 million as reported on the Consolidated Statements of Financial Position.

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

There are no material restrictions on the Company's cash with the exception of cash in trust of $59 million related to cash collateral and for specific shipper commitments. Cash and cash equivalents held by EEP and the Fund are generally not readily accessible by Enbridge until distributions are declared and paid by these entities, which occurs quarterly for EEP and monthly for the Fund. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by Enbridge.

OPERATING ACTIVITIES

Cash generated from operating activities was $1,510 million for the three months ended March 31, 2015 compared with $333 million for the three months ended March 31, 2014.

Despite the decrease in earnings period-over-period as discussed in *Financial Results*, cash from operating activities increased by approximately $1,177 million for the three months ended March 31, 2015 relative to the comparable period in 2014. The main contributor relates to a period-over-period change in operating assets and liabilities of approximately $964 million resulting primarily from a negative impact in the comparative period in 2014 related to significantly higher natural gas prices combined with colder weather within the Company's gas distribution business, which resulted in the Company accumulating a significant regulatory receivable. In addition, fluctuations in crude oil prices within Sponsored Investments during the first quarter of 2015, as well as other normal course factors including timing of cash receipts and payments, also contributed to the positive change in operating assets and liabilities. Furthermore, cash from operating activities was positively impacted by higher throughputs and tolls on EEP's major liquids pipelines as well as contributions from new assets placed into service in 2014.

At March 31, 2015, the Company had a negative working capital position. Despite this negative working capital, the Company continues to have significant liquidity available through committed credit facilities, which allow the funding of liabilities as they become due. As discussed above, as at March 31, 2015, the Company's net available liquidity totalled $9,038 million (December 31, 2014 - $9,291 million). In addition, it is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

INVESTING ACTIVITIES

Cash used in investing activities was $1,866 million for the three months ended March 31, 2015 compared with $2,743 million for the three months ended March 31, 2014. The Company continues with the execution of its growth projects, which are further described in *Growth Projects – Commercially Secured Projects*. The timing of project approval, construction and in-service dates impact the timing of cash requirements. Cash used in investing activities has decreased period-over-period primarily due to the successful completion in 2014 of growth projects including the Flanagan South Pipeline and the Seaway Twinning/Extension which required significant investments during the first quarter of 2014.

FINANCING ACTIVITIES

Cash generated from financing activities was $225 million for the three months ended March 31, 2015 compared with $2,465 million for the three months ended March 31, 2014. The reduction of the cash generated from financing relative to the comparable period in 2014 reflects lower capital requirements.

During the first quarter of 2015, the Company increased its overall debt by $189 million. The most significant contributor was an increase in credit facilities and commercial paper draws of $1,021 million, partially offset by repayments of medium-term notes and short-term borrowings of $376 million and $456 million respectively. For the comparative period in 2014, the Company increased its overall debt by $2,527 million. The most significant contributors were the issuance of medium-term notes, net of repayments, of $1,328 million, credit facilities and commercial paper draws, net of repayments, of $838 million and increased short-term borrowings, net of repayments, of $361 million.

Furthermore, during the first quarter of 2014 the Company raised net proceeds of $268 million in preference shares (2015 - nil) and $16 million (2015 - $8 million) in common shares through routine exercises of stock options. Additional preference and common shares outstanding in 2015 together with a 33% increase in the common share dividend rate, gave rise to an increase in dividends paid during the first three months of 2015 compared with the same period in 2014.

Financing activities also included transactions between the Company's Sponsored Investments and their public unitholders, also referred to as noncontrolling interests. During the first quarter of 2015, sponsored vehicles received contributions, net of distributions, of $340 million, primarily as a result of their equity issuances to the public. During the comparative period in 2014, these sponsored vehicles made distributions, net of contributions, of $107 million.

Dividend Reinvestment and Share Purchase Plan

Participants in the Company's Dividend Reinvestment and Share Purchase Plan receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended March 31, 2015, dividends declared were $396 million (2014 - $291 million), of which $241 million (2014 - $185 million) were paid in cash and reflected in financing activities. The remaining $155 million (2014 - $106 million) of dividends declared were reinvested pursuant to the plan and resulted in the issuance of common shares rather than a cash payment. For the three months ended March 31, 2015, 39.1% (2014 - 36.4%) of total dividends declared were reinvested.

On May 5, 2015, the Enbridge Board of Directors declared the following quarterly dividends. All dividends are payable on June 1, 2015 to shareholders of record on May 15, 2015.

Common Shares	$0.46500
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.25000
Preference Shares, Series D	$0.25000
Preference Shares, Series F	$0.25000
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.25000
Preference Shares, Series L	US$0.25000
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1	US$0.25000
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13	$0.27500
Preference Shares, Series 15	$0.27500

CAPITAL EXPENDITURE COMMITMENTS

The Company has signed contracts for the purchase of services, pipe and other materials totalling $3,436 million which are expected to be paid over the next five years.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

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

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

Interest Rate Risk
The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

The Company's earnings and cash flows are also exposed to variability in longer-term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 4.0%.

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

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

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

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

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

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**45**	29
Interest rate contracts	**(664)**	(242)
Commodity contracts	**19**	(7)
Other contracts	**(8)**	5
Net investment hedges		
Foreign exchange contracts	**(123)**	(48)
	(731)	(263)
Amount of gains/(loss) reclassified from Accumulated other comprehensive income (AOCI) to earnings *(effective portion)*		
Foreign exchange contracts[1]	**-**	(1)
Interest rate contracts[2]	**10**	21
Commodity contracts[3]	**(20)**	7
Other contracts[4]	**5**	(4)
	(5)	23
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**(23)**	25
Commodity contracts[3]	**5**	1
	(18)	26
Amount of gains/(loss) from non-qualifying derivatives included in earnings		
Foreign exchange contracts[1]	**(1,293)**	(420)
Interest rate contracts[2]	**-**	1
Commodity contracts[3]	**(192)**	173
Other contracts[4]	**2**	5
	(1,483)	(241)

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

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. However, until the Canadian Restructuring Plan is complete, which is targeted for mid-2015, the Company may not access the public markets as regularly as it has in recent quarters. The Company, through committed credit facilities with a diversified group of banks and institutions, targets to maintain sufficient liquidity to enable it to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at March 31, 2015. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

CREDIT RISK

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

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

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

FAIR VALUE MEASUREMENTS

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

CRITICAL ACCOUNTING ESTIMATES

ASSET RETIREMENT OBLIGATIONS

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

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

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

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

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

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

FUTURE ACCOUNTING POLICY CHANGES

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

Simplifying the Presentation of Debt Issuance Costs
ASU 2015-03 was issued in April 2015 with the intent to simplify the presentation of debt issuance costs. The new standard requires a debt issuance cost related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, as consistent with the presentation of debt discounts or premiums. This accounting update is effective for financial statements issued for fiscal years beginning after December 15, 2015 on a retrospective basis. The adoption of the pronouncement is not anticipated to have a material impact on the Company's consolidated financial statements.

Amendments to the Consolidation Analysis
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Revenue from Contracts with Customers
ASU 2014-09 was issued in May 2014 with the intent of significantly enhancing comparability of revenue recognition practices across entities and industries. The new standard provides a single principles-based, five-step model to be applied to all contracts with customers and introduces new, increased disclosure requirements. The Company is currently assessing the impact of the new standard on its consolidated

financial statements. The new standard is effective for annual and interim periods beginning on or after December 15, 2016 and may be applied on either a full or modified retrospective basis.

QUARTERLY FINANCIAL INFORMATION[1]

	2015	2014				2013		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
(millions of Canadian dollars, except per share amounts)								
Revenues	**7,929**	8,797	8,297	10,026	10,521	8,293	8,998	7,730
Earnings/(loss) attributable to common shareholders	**(383)**	88	(80)	756	390	(267)	421	42
Earnings/(loss) per common share	**(0.46)**	0.11	(0.10)	0.92	0.48	(0.33)	0.52	0.05
Diluted earnings/(loss) per common share	**(0.46)**	0.10	(0.10)	0.91	0.47	(0.33)	0.51	0.05
Dividends per common share	**0.465**	0.350	0.350	0.350	0.350	0.315	0.315	0.315
EGD - warmer/(colder) than normal weather	**(33)**	(1)	2	(4)	(33)	(13)	-	(2)
Changes in unrealized derivative fair value (gains)/loss	**977**	164	396	(430)	190	613	(223)	246

1 *Quarterly financial information has been extracted from financial statements prepared in accordance with U.S. GAAP.*

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

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

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

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

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

- Included in the fourth quarter of 2014 was the tax impact of an asset transfer between entities under common control of Enbridge. The intercompany gain realized by the selling entity has been eliminated from the Company’s consolidated financial statements. However, as the transaction involved sale of partnership units, the tax consequences have remained in consolidated earnings and resulted in a charge of $157 million.
- Included in first and fourth quarter earnings for 2014 were $43 million and $14 million after-tax gain on the disposal of non-core Offshore assets. Earnings in the first quarter of 2014 also included a $14

million after-tax gain on the sale of an Alternative and Emerging Technologies investment within the Corporate segment.

- Included in earnings is the Company's share of after-tax leak remediation costs associated with the Line 6B crude oil release. Remediation costs of $5 million and $12 million were recognized in the second and third quarters of 2014; and $6 million, $5 million and $9 million were recognized in the second, third and fourth quarters of 2013. In the fourth quarter of 2014, the Company recognized an out-of-period adjustment of $5 million to reduce Enbridge's share of leak remediation costs recognized in the third quarter of 2014. Earnings also included insurance recoveries associated with the Line 6B crude oil release of $6 million in the second quarter of 2013.
- Included in earnings are after-tax costs of $4 million in the third quarter of 2014 as well as $40 million, $13 million and $3 million incurred respectively in the second, third and fourth quarters of 2013, in connection with the Line 37 crude oil release which occurred in June 2013. Earnings also reflected insurance recoveries associated with the Line 37 crude oil release of $9 million recognized in the first quarter of 2015 and $4 million recognized in each of the second quarter and fourth quarter of 2014, respectively.

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

OUTSTANDING SHARE DATA[1]

PREFERENCE SHARES

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

COMMON SHARES

	Number
Common Shares - issued and outstanding (voting equity shares)	856,691,277
Stock Options - issued and outstanding (21,534,146 vested)	38,262,084

1 Outstanding share data information is provided as at April 24, 2015.

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

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

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

March 31, 2015

CONSOLIDATED STATEMENTS OF EARNINGS

(unaudited; millions of Canadian dollars, except per share amounts)	Three months ended March 31, 2015	2014
Revenues		
Commodity sales	**5,231**	8,006
Gas distribution sales	**1,591**	1,111
Transportation and other services	**1,107**	1,404
	7,929	10,521
Expenses		
Commodity costs	**5,042**	7,733
Gas distribution costs	**1,364**	846
Operating and administrative	**991**	745
Depreciation and amortization	**474**	366
Environmental costs, net of recoveries	**(11)**	5
	7,860	9,695
	69	826
Income from equity investments	**133**	114
Other expense	**(457)**	(138)
Interest expense	**(251)**	(238)
	(506)	564
Income taxes recovery/(expense) *(Note 11)*	**285**	(117)
Earnings/(loss) from continuing operations	**(221)**	447
Discontinued operations *(Note 4)*		
Earnings from discontinued operations before income taxes	**-**	73
Income taxes from discontinued operations	**-**	(27)
Earnings from discontinued operations	**-**	46
Earnings/(loss)	**(221)**	493
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(90)**	(48)
Earnings/(loss) attributable to Enbridge Inc.	**(311)**	445
Preference share dividends	**(72)**	(55)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**(383)**	390
Earnings/(loss) attributable to Enbridge Inc. common shareholders		
Earnings/(loss) from continuing operations	**(383)**	344
Earnings from discontinued operations, net of tax	**-**	46
	(383)	390
Earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 7)*		
Continuing operations	**(0.46)**	0.42
Discontinued operations	**-**	0.06
	(0.46)	0.48
Diluted earnings/(loss) per common share attributable to Enbridge Inc. common shareholders *(Note 7)*		
Continuing operations	**(0.46)**	0.41
Discontinued operations	**-**	0.06
	(0.46)	0.47

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended March 31,	
	2015	2014
(unaudited; millions of Canadian dollars)		
Earnings/(loss)	**(221)**	493
Other comprehensive income/(loss), net of tax		
Change in unrealized loss on cash flow hedges	**(505)**	(304)
Change in unrealized loss on net investment hedges	**(426)**	(89)
Other comprehensive income from equity investees	**9**	4
Reclassification to earnings of realized cash flow hedges	**(9)**	40
Reclassification to earnings of unrealized cash flow hedges	**(30)**	20
Reclassification to earnings of pension plans and other postretirement benefits (OPEB) amortization amounts	**4**	1
Change in foreign currency translation adjustment	**1,597**	523
Other comprehensive income	**640**	195
Comprehensive income	**419**	688
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	**(125)**	(141)
Comprehensive income attributable to Enbridge Inc.	**294**	547
Preference share dividends	**(72)**	(55)
Comprehensive income attributable to Enbridge Inc. common shareholders	**222**	492

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended March 31,	
	2015	2014
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares		
Balance at beginning of period	**6,515**	5,141
Preference shares issued	**-**	270
Balance at end of period	**6,515**	5,411
Common shares		
Balance at beginning of period	**6,669**	5,744
Dividend reinvestment and share purchase plan	**155**	106
Shares issued on exercise of stock options	**13**	24
Balance at end of period	**6,837**	5,874
Additional paid-in capital		
Balance at beginning of period	**2,549**	746
Drop down of interest to Enbridge Energy Partners, L.P. *(Note 9)*	**218**	-
Stock-based compensation	**16**	12
Options exercised	**(5)**	(9)
Dilution gains and other	**34**	(4)
Balance at end of period	**2,812**	745
Retained earnings		
Balance at beginning of period	**1,571**	2,550
Earnings/(loss) attributable to Enbridge Inc.	**(311)**	445
Preference share dividends	**(72)**	(55)
Common share dividends declared	**(396)**	(291)
Dividends paid to reciprocal shareholder	**6**	4
Redemption value adjustment attributable to redeemable noncontrolling interests	**182**	(148)
Balance at end of period	**980**	2,505
Accumulated other comprehensive income/(loss) *(Note 8)*		
Balance at beginning of period	**(435)**	(599)
Other comprehensive income attributable to Enbridge Inc. common shareholders	**605**	102
Balance at end of period	**170**	(497)
Reciprocal shareholding - balance at beginning and end of period	**(83)**	(86)
Total Enbridge Inc. shareholders' equity	**17,231**	13,952
Noncontrolling interests		
Balance at beginning of period	**2,015**	4,014
Earnings attributable to noncontrolling interests	**74**	45
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized loss on cash flow hedges	**(111)**	(70)
Change in foreign currency translation adjustment	**157**	155
Reclassification to earnings of realized cash flow hedges	**(4)**	10
Reclassification to earnings of unrealized cash flow hedges	**(23)**	3
	19	98
Comprehensive income attributable to noncontrolling interests	**93**	143
Distributions	**(158)**	(130)
Contributions	**525**	41
Drop down of interest to Enbridge Energy Partners, L.P. *(Note 9)*	**(304)**	-
Dilution loss	**(53)**	-
Other	**2**	(2)
Balance at end of period	**2,120**	4,066
Total equity	**19,351**	18,018
Dividends paid per common share	**0.465**	0.350

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended March 31, 2015	2014
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings/(loss)	**(221)**	493
Earnings from discontinued operations	**-**	(46)
Depreciation and amortization	**474**	366
Deferred income taxes	**(322)**	69
Changes in unrealized loss on derivative instruments, net	**1,483**	244
Cash distributions in excess of equity earnings	**46**	12
Gain on disposition	**(5)**	(16)
Hedge ineffectiveness *(Note 10)*	**(18)**	26
Inventory revaluation allowance	**43**	2
Other	**(106)**	34
Changes in regulatory assets and liabilities	**11**	5
Changes in environmental liabilities, net of recoveries	**(10)**	(46)
Changes in operating assets and liabilities	**135**	(829)
Cash provided by continuing operations	**1,510**	314
Cash provided by discontinued operations *(Note 4)*	**-**	19
	1,510	333
Investing activities		
Additions to property, plant and equipment	**(1,590)**	(2,408)
Long-term investments	**(142)**	(313)
Additions to intangible assets	**(19)**	(53)
Acquisition	**(106)**	-
Proceeds from disposition	**-**	19
Affiliate loans, net	**3**	3
Changes in restricted cash	**(12)**	5
Cash provided by continuing operations	**(1,866)**	(2,747)
Cash provided by discontinued operations *(Note 4)*	**-**	4
	(1,866)	(2,743)
Financing activities		
Net change in bank indebtedness and short-term borrowings	**(456)**	361
Net change in commercial paper and credit facility draws	**1,021**	838
Debenture and term note issues	**-**	1,528
Debenture and term note repayments	**(376)**	(200)
Contributions from noncontrolling interests	**525**	41
Distributions to noncontrolling interests	**(158)**	(130)
Distributions to redeemable noncontrolling interests	**(27)**	(18)
Preference shares issued	**-**	268
Common shares issued	**8**	16
Preference share dividends	**(71)**	(54)
Common share dividends	**(241)**	(185)
	225	2,465
Effect of translation of foreign denominated cash and cash equivalents	**61**	18
Increase/(decrease) in cash and cash equivalents	**(70)**	73
Cash and cash equivalents at beginning of period - discontinued operations	**-**	20
Cash and cash equivalents at beginning of period - continuing operations	**1,261**	756
Cash and cash equivalents at end of period	**1,191**	849

See accompanying notes to the unaudited interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	March 31, 2015	December 31, 2014
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**1,191**	1,261
Restricted cash	**59**	47
Accounts receivable and other *(Note 5)*	**5,392**	5,504
Accounts receivable from affiliates	**86**	241
Inventory	**1,041**	1,148
	7,769	8,201
Property, plant and equipment, net	**57,861**	53,830
Long-term investments	**6,120**	5,408
Deferred amounts and other assets	**3,210**	3,208
Intangible assets, net	**1,235**	1,166
Goodwill	**525**	483
Deferred income taxes	**745**	561
	77,465	72,857
Liabilities and equity		
Current liabilities		
Bank indebtedness	**269**	507
Short-term borrowings	**823**	1,041
Accounts payable and other	**7,287**	6,444
Accounts payable to affiliates	**45**	80
Interest payable	**325**	264
Environmental liabilities	**158**	161
Current maturities of long-term debt *(Note 6)*	**660**	1,004
	9,567	9,501
Long-term debt *(Note 6)*	**35,785**	33,423
Other long-term liabilities	**5,740**	4,041
Deferred income taxes	**4,948**	4,842
	56,040	51,807
Contingencies *(Note 13)*		
Redeemable noncontrolling interests	**2,074**	2,249
Equity		
Share capital		
Preference shares	**6,515**	6,515
Common shares (855 and 852 outstanding at March 31, 2015 and December 31, 2014, respectively)	**6,837**	6,669
Additional paid-in capital	**2,812**	2,549
Retained earnings	**980**	1,571
Accumulated other comprehensive income/(loss) *(Note 8)*	**170**	(435)
Reciprocal shareholding	**(83)**	(83)
Total Enbridge Inc. shareholders' equity	**17,231**	16,786
Noncontrolling interests	**2,120**	2,015
	19,351	18,801
	77,465	72,857

See accompanying notes to the unaudited consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements of Enbridge Inc. (Enbridge or the Company) have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. Accordingly, they do not include all of the information and footnotes required by U.S. GAAP for complete consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements and notes thereto for the year ended December 31, 2014. In the opinion of management, the interim consolidated financial statements contain all adjustments, consisting only of normal recurring adjustments with the exception of an out-of-period adjustment further described in Note 3, Segmented Information, which management considers necessary to present fairly the Company's financial position as at March 31, 2015 and results of operations and cash flows for the three months ended March 31, 2015 and 2014. These interim consolidated financial statements follow the same significant accounting policies as those included in the Company's consolidated financial statements as at and for the year ended December 31, 2014, except for the adoption of new standards *(Note 2)*. Amounts are stated in Canadian dollars unless otherwise noted.

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

2. SIGNIFICANT ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

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

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Measurement Date of Defined Benefit Obligation and Plan Assets
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3. SEGMENTED INFORMATION

Three months ended March 31, 2015	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	**29**	**1,788**	**4,232**	**1,880**	**-**	**7,929**
Commodity and gas distribution costs	**-**	**(1,364)**	**(4,092)**	**(948)**	**(2)**	**(6,406)**
Operating and administrative	**(422)**	**(134)**	**(55)**	**(384)**	**4**	**(991)**
Depreciation and amortization	**(150)**	**(77)**	**(48)**	**(194)**	**(5)**	**(474)**
Environmental costs, net of recoveries	**12**	**-**	**-**	**(1)**	**-**	**11**
	(531)	**213**	**37**	**353**	**(3)**	**69**
Income from equity investments	**60**	**-**	**14**	**45**	**14**	**133**
Other income/(expense)	**(4)**	**(1)**	**6**	**(9)**	**(449)**	**(457)**
Interest income/(expense)	**(142)**	**(42)**	**(30)**	**(86)**	**49**	**(251)**
Income taxes recovery/(expense)	**196**	**(31)**	**(12)**	**(82)**	**214**	**285**
Earnings/(loss)	**(421)**	**139**	**15**	**221**	**(175)**	**(221)**
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(1)**	**-**	**1**	**(90)**	**-**	**(90)**
Preference share dividends	**-**	**-**	**-**	**-**	**(72)**	**(72)**
Earnings/(loss) attributable to Enbridge Inc. common shareholders	**(422)**	**139**	**16**	**131**	**(247)**	**(383)**
Additions to property, plant and equipment[2]	**824**	**106**	**80**	**566**	**14**	**1,590**

Three months ended March 31, 2014	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing and Energy Services	Sponsored Investments	Corporate[1]	Consolidated
(millions of Canadian dollars)						
Revenues	447	1,285	6,422	2,367	-	10,521
Commodity and gas distribution costs	-	(846)	(6,119)	(1,614)	-	(8,579)
Operating and administrative	(256)	(133)	(34)	(323)	1	(745)
Depreciation and amortization	(117)	(84)	(12)	(149)	(4)	(366)
Environmental costs, net of recoveries	-	-	-	(5)	-	(5)
	74	222	257	276	(3)	826
Income from equity investments	36	-	49	18	11	114
Other income/(expense)	1	3	5	(1)	(146)	(138)
Interest income/(expense)	(87)	(40)	(18)	(111)	18	(238)
Income taxes recovery/(expense)	21	(49)	(102)	(51)	64	(117)
Earnings/(loss) from continuing operations	45	136	191	131	(56)	447
Discontinued operations						
Earnings from discontinued operations before income taxes	-	-	73	-	-	73
Income taxes from discontinued operations	-	-	(27)	-	-	(27)
Earnings from discontinued operations	-	-	46	-	-	46
Earnings/(loss)	45	136	237	131	(56)	493
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(1)	-	-	(47)	-	(48)
Preference share dividends	-	-	-	-	(55)	(55)
Earnings/(loss) attributable to Enbridge Inc. common shareholders	44	136	237	84	(111)	390
Additions to property, plant and equipment[2]	1,498	97	118	682	14	2,409

1 *Included within the Corporate segment was Interest income of $196 million (2014 - $155 million) charged to other operating segments.*

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

OUT-OF-PERIOD ADJUSTMENT

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

TOTAL ASSETS

	March 31, 2015	December 31, 2014
(millions of Canadian dollars)		
Liquids Pipelines	**29,536**	27,657
Gas Distribution	**9,143**	9,320
Gas Pipelines, Processing and Energy Services	**8,183**	7,601
Sponsored Investments	**25,751**	23,515
Corporate	**4,852**	4,764
	77,465	72,857

4. DISCONTINUED OPERATIONS

In March 2014, the Company completed the sale of certain of its Enbridge Offshore Pipelines assets located within the Stingray corridor to an unrelated third party for cash proceeds of $11 million (US$10 million), subject to working capital adjustments. The gain of $70 million (US$63 million), which resulted from the cash proceeds and the disposition of net liabilities held for sale of $59 million (US$53 million), is presented as Earnings from discontinued operations for the three months ended March 31, 2014. The results of operations, including revenues of $4 million and related cash flows, have also been presented as discontinued operations for the three months ended March 31, 2014. These amounts are included within the Gas Pipelines, Processing and Energy Services segment.

5. ACCOUNTS RECEIVABLE AND OTHER

Pursuant to a Receivables Purchase Agreement (the Receivables Agreement) executed in 2013, certain trade and accrued receivables (the Receivables) have been sold by certain Enbridge Energy Partners, L.P. (EEP) subsidiaries to an Enbridge wholly-owned special purpose entity (SPE). The Receivables owned by the SPE are not available to Enbridge except through its 100% ownership in such SPE. The Receivables Agreement provides for purchases to occur on a monthly basis through to December 2016, provided accumulated purchases net of collections do not exceed US$450 million at any one point. The value of trade and accrued receivables outstanding owned by the SPE totalled US$364 million ($462 million) and US$378 million ($439 million) as at March 31, 2015 and December 31, 2014, respectively.

6. DEBT

The following table provides details of the Company's committed credit facilities at March 31, 2015 and December 31, 2014.

		March 31, 2015			December 31, 2014
	Maturity Dates	Total Facilities	Draws[1]	Available	Total Facilities
(millions of Canadian dollars)					
Liquids Pipelines	2016	**300**	**296**	**4**	300
Gas Distribution	2016-2019	**1,009**	**829**	**180**	1,008
Sponsored Investments	2016-2019	**4,907**	**3,483**	**1,424**	4,531
Corporate	2016-2019	**13,365**	**6,857**	**6,508**	12,772
Total committed credit facilities		**19,581**	**11,465**	**8,116**	18,611

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

In addition to the committed credit facilities noted above, the Company also has $385 million (December 31, 2014 - $361 million) of uncommitted demand credit facilities, of which $103 million (December 31, 2014 - $80 million) was unutilized as at March 31, 2015.

Credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and the Company has the option to extend the facilities, which are currently set to mature from 2016 to 2019.

Commercial paper and credit facility draws, net of short-term borrowings, of $10,387 million (December 31, 2014 - $8,960 million) are supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

7. EARNINGS PER COMMON SHARE

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 12 million (2014 - 12 million) for the three months ended March 31, 2015, resulting from the Company's reciprocal investment in Noverco Inc.

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

	Three months ended March 31,	
	2015	2014
(number of shares in millions)		
Weighted average shares outstanding	**841**	820
Effect of dilutive options	**13**	10
Diluted weighted average shares outstanding	**854**	830

For the three months ended March 31, 2015, 5,851,770 anti-dilutive stock options (2014 - 12,209,636) with a weighted average exercise price of $59.14 (2014 - $46.77) were excluded from the diluted earnings per common share calculation.

8. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated other comprehensive income/(loss) (AOCI) attributable to Enbridge common shareholders for the three months ended March 31, 2015 and 2014 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2015	**(488)**	**108**	**309**	**(5)**	**(359)**	**(435)**
Other comprehensive income/(loss) retained in AOCI	**(515)**	**(457)**	**1,413**	**10**	**-**	**451**
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	**(7)**	**-**	**-**	**-**	**-**	**(7)**
Commodity contracts[2]	**(10)**	**-**	**-**	**-**	**-**	**(10)**
Other contracts[4]	**5**	**-**	**-**	**-**	**-**	**5**
Amortization of pension and OPEB actuarial loss[5]	**-**	**-**	**-**	**-**	**6**	**6**
	(527)	**(457)**	**1,413**	**10**	**6**	**445**
Tax impact						
Income tax on amounts retained in AOCI	**132**	**31**	**-**	**(1)**	**-**	**162**
Income tax on amounts reclassified to earnings	**-**	**-**	**-**	**-**	**(2)**	**(2)**
	132	**31**	**-**	**(1)**	**(2)**	**160**
Balance at March 31, 2015	**(883)**	**(318)**	**1,722**	**4**	**(355)**	**170**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Amortization Adjustment	Total
(millions of Canadian dollars)						
Balance at January 1, 2014	(1)	378	(778)	(15)	(183)	(599)
Other comprehensive income/(loss) retained in AOCI	(308)	(103)	368	4	-	(39)
Other comprehensive gains/(loss) reclassified to earnings						
Interest rate contracts[1]	37	-	-	-	-	37
Commodity contracts[2]	4	-	-	-	-	4
Foreign exchange contracts[3]	15	-	-	-	-	15
Other contracts[4]	(4)	-	-	-	-	(4)
Amortization of pension and OPEB actuarial loss[5]	-	-	-	-	3	3
	(256)	(103)	368	4	3	16
Tax impact						
Income tax on amounts retained in AOCI	79	14	-	-	-	93
Income tax on amounts reclassified to earnings	(5)	-	-	-	(2)	(7)
	74	14	-	-	(2)	86
Balance at March 31, 2014	(183)	289	(410)	(11)	(182)	(497)

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Commodity costs in the Consolidated Statements of Earnings.
3 Reported within Other expense in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
5 These components are included in the computation of net periodic pension costs and are reported within Operating and administrative expense in the Consolidated Statements of Earnings.

9. NONCONTROLLING INTERESTS

ALBERTA CLIPPER DROP DOWN

On January 2, 2015, Enbridge transferred its 66.7% interest in the United States segment of the Alberta Clipper pipeline, held through a wholly-owned Enbridge subsidiary in the United States, to EEP for aggregate consideration of $1.1 billion (US$1 billion), consisting of approximately $814 million (US$694 million) of Class E equity units issued to Enbridge by EEP and the repayment of approximately $359 million (US$306 million) of indebtedness owed to Enbridge. Prior to the transfer, EEP owned the remaining 33.3% interest in the United States segment of the Alberta Clipper pipeline.

The Class E units issued to Enbridge are entitled to the same distributions as the Class A units held by the public and are convertible into Class A units on a one-for-one basis at Enbridge's option. The transaction applies to all distributions declared subsequent to the transfer. The Class E units are redeemable at EEP's option after 30 years, if not converted by Enbridge prior to that time. The units have a liquidation preference equal to their notional value at December 23, 2014 of US$38.31 per unit, which was determined based on the trailing five-day volume-weighted average price of EEP's Class A common units. Enbridge’s economic interest in EEP increased from 33.7% to 36.6% as a result of the transfer. EEP recorded the Class E units at fair value. As a result, the Company recorded a decrease in Noncontrolling interests of $304 million and increases in Additional paid-in capital and Deferred income tax liabilities of $218 and $86 million, respectively.

EEP ISSUANCE OF CLASS A UNITS

In March 2015, EEP completed a listed share issuance. The Company participated only to the extent to maintain its 2% General Partner interest, resulting in a decrease in the overall economic interest from 36.6% to 35.9%. The listed share issuance resulted in contributions of $366 million (US $289 million) from noncontrolling interest holders.

10. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

Foreign Exchange Risk

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

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

Interest Rate Risk

The Company's earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps and options are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

The Company's earnings and cash flows are also exposed to variability in longer-term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate its exposure to long-term interest rate variability on select forecast term debt issuances through 2019 via execution of floating to fixed interest rate swaps with an average swap rate of 4.0%.

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

Commodity Price Risk

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

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in the Company's share price. The Company has exposure to its own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. The

Company uses equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted stock units. The Company uses a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the Consolidated Statements of Financial Position location and carrying value of the Company's derivative instruments. The Company did not have any outstanding fair value hedges as at March 31, 2015 or December 31, 2014.

The Company generally has a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) agreements, or other similar derivative agreements, with the majority of its derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit event, and would reduce the Company's credit risk exposure on derivative asset positions outstanding with the counterparties in these particular circumstances. The following table also summarizes the maximum potential settlement in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

March 31, 2015	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**4**	**5**	**1**	**10**	**(7)**	**3**
Interest rate contracts	**3**	**-**	**-**	**3**	**(3)**	**-**
Commodity contracts	**26**	**-**	**384**	**410**	**(164)**	**246**
Other contracts	**2**	**-**	**10**	**12**	**-**	**12**
	35	**5**	**395**	**435**	**(174)**	**261**
Deferred amounts and other assets						
Foreign exchange contracts	**74**	**11**	**-**	**85**	**(85)**	**-**
Interest rate contracts	**-**	**-**	**-**	**-**	**-**	**-**
Commodity contracts	**24**	**-**	**120**	**144**	**(12)**	**132**
Other contracts	**4**	**-**	**3**	**7**	**-**	**7**
	102	**11**	**123**	**236**	**(97)**	**139**
Accounts payable and other						
Foreign exchange contracts	**-**	**(80)**	**(442)**	**(522)**	**7**	**(515)**
Interest rate contracts	**(684)**	**-**	**-**	**(684)**	**3**	**(681)**
Commodity contracts	**-**	**-**	**(298)**	**(298)**	**94**	**(204)**
	(684)	**(80)**	**(740)**	**(1,504)**	**104**	**(1,400)**
Other long-term liabilities						
Foreign exchange contracts	**-**	**(163)**	**(2,214)**	**(2,377)**	**85**	**(2,292)**
Interest rate contracts	**(974)**	**-**	**-**	**(974)**	**-**	**(974)**
Commodity contracts	**-**	**-**	**(366)**	**(366)**	**54**	**(312)**
	(974)	**(163)**	**(2,580)**	**(3,717)**	**139**	**(3,578)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**78**	**(227)**	**(2,655)**	**(2,804)**	**-**	**(2,804)**
Interest rate contracts	**(1,655)**	**-**	**-**	**(1,655)**	**-**	**(1,655)**
Commodity contracts	**50**	**-**	**(160)**	**(110)**	**(28)**[1]	**(138)**
Other contracts	**6**	**-**	**13**	**19**	**-**	**19**
	(1,521)	**(227)**	**(2,802)**	**(4,550)**	**(28)**	**(4,578)**

1 Amount available for offset includes $28 million of cash collateral.

December 31, 2014	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	3	7	3	13	(13)	-
Interest rate contracts	8	-	-	8	(7)	1
Commodity contracts	34	-	501	535	(130)	405
Other contracts	4	-	8	12	-	12
	49	7	512	568	(150)	418
Deferred amounts and other assets						
Foreign exchange contracts	33	18	-	51	(51)	-
Interest rate contracts	5	-	-	5	(5)	-
Commodity contracts	17	-	118	135	(43)	92
Other contracts	5	-	3	8	-	8
	60	18	121	199	(99)	100
Accounts payable and other						
Foreign exchange contracts	(3)	(80)	(218)	(301)	13	(288)
Interest rate contracts	(438)	-	-	(438)	7	(431)
Commodity contracts	-	-	(281)	(281)	97	(184)
	(441)	(80)	(499)	(1,020)	117	(903)
Other long-term liabilities						
Foreign exchange contracts	-	(49)	(1,147)	(1,196)	51	(1,145)
Interest rate contracts	(576)	-	-	(576)	5	(571)
Commodity contracts	-	-	(306)	(306)	43	(263)
	(576)	(49)	(1,453)	(2,078)	99	(1,979)
Total net derivative asset/(liability)						
Foreign exchange contracts	33	(104)	(1,362)	(1,433)	-	(1,433)
Interest rate contracts	(1,001)	-	-	(1,001)	-	(1,001)
Commodity contracts	51	-	32	83	(33)[1]	50
Other contracts	9	-	11	20	-	20
	(908)	(104)	(1,319)	(2,331)	(33)	(2,364)

1 Amount available for offset includes $33 million of cash collateral.

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

March 31, 2015	2015	2016	2017	2018	2019	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**272**	**25**	**413**	**2**	**2**	**2**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**2,478**	**2,690**	**2,832**	**3,100**	**2,441**	**2,901**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	**1**	**-**	**-**	**-**	**-**	**-**
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**4,531**	**5,728**	**5,039**	**3,669**	**234**	**490**
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	**3,723**	**1,816**	**2,524**	**1,214**	**-**	**-**
Equity contracts *(millions of Canadian dollars)*	**41**	**51**	**-**	**-**	**-**	**-**
Commodity contracts - natural gas *(billions of cubic feet)*	**(49)**	**(38)**	**(37)**	**(17)**	**2**	**-**
Commodity contracts - crude oil *(millions of barrels)*	**-**	**(18)**	**(18)**	**(9)**	**-**	**-**
Commodity contracts - NGL *(millions of barrels)*	**(12)**	**(9)**	**-**	**-**	**-**	**-**
Commodity contracts - power *(megawatt hours (MWH))*	**22**	**40**	**40**	**30**	**31**	**(23)**

December 31, 2014	2015	2016	2017	2018	2019	Thereafter
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	240	25	413	2	2	2
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	3,203	2,470	2,832	3,100	2,441	2,901
Foreign exchange contracts - Euro forwards - purchase *(millions of Euros)*	15	-	-	-	-	-
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	5,767	5,486	4,851	3,529	222	469
Interest rate contracts - long-term debt *(millions of Canadian dollars)*	3,528	1,762	2,470	1,176	-	-
Equity contracts *(millions of Canadian dollars)*	41	51	-	-	-	-
Commodity contracts - natural gas *(billions of cubic feet)*	(62)	(10)	(25)	(1)	-	-
Commodity contracts - crude oil *(millions of barrels)*	3	(18)	(18)	(9)	-	-
Commodity contracts - NGL *(millions of barrels)*	(5)	-	-	-	-	-
Commodity contracts - power *(MWH)*	25	40	40	30	31	-

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

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

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Amount of unrealized gains/(loss) recognized in OCI		
Cash flow hedges		
Foreign exchange contracts	**45**	29
Interest rate contracts	**(664)**	(242)
Commodity contracts	**19**	(7)
Other contracts	**(8)**	5
Net investment hedges		
Foreign exchange contracts	**(123)**	(48)
	(731)	(263)
Amount of gains/(loss) reclassified from AOCI to earnings *(effective portion)*		
Foreign exchange contracts[1]	**-**	(1)
Interest rate contracts[2]	**10**	21
Commodity contracts[3]	**(20)**	7
Other contracts[4]	**5**	(4)
	(5)	23
Amount of gains/(loss) reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*		
Interest rate contracts[2]	**(23)**	25
Commodity contracts[3]	**5**	1
	(18)	26

1 *Reported within Transportation and other services revenues in the Consolidated Statements of Earnings.*
2 *Reported as an increase/(decrease)within Interest expense in the Consolidated Statements of Earnings.*
3 *Reported within Commodity costs in the Consolidated Statements of Earnings.*
4 *Reported within Operating and administrative expense in the Consolidated Statements of Earnings.*

The Company estimates that $102 million of AOCI related to cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 45 months as at March 31, 2015.

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

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Foreign exchange contracts[1]	**(1,293)**	(420)
Interest rate contracts[2]	**-**	1
Commodity contracts[3]	**(192)**	173
Other contracts[4]	**2**	5
Total unrealized derivative fair value loss	**(1,483)**	(241)

1 Reported within Transportation and other services revenues (2015 - $795 million loss; 2014 - $231 million loss) and Other expense (2015 - $498 million loss; 2014 - $189 million loss) in the Consolidated Statements of Earnings.
2 Reported as an increase/(decrease) within Interest expense in the Consolidated Statements of Earnings.
3 Reported within Transportation and other services revenues (2015 - $18 million loss; 2014 - $134 million gain), Commodity costs (2015 - $143 million loss; 2014 - $40 million gain) and Operating and administrative expense (2015 - $31 million loss; 2014 - $1 million loss) in the Consolidated Statements of Earnings.
4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

LIQUIDITY RISK
Liquidity risk is the risk the Company will not be able to meet its financial obligations, including commitments and guarantees, as they become due. In order to manage this risk, the Company forecasts cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. The Company maintains current shelf prospectuses with securities regulators, which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. The Company, through committed credit facilities with a diversified group of banks and institutions, targets to maintain sufficient liquidity to enable it to fund all anticipated requirements for approximately one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities as at March 31, 2015. As a result, all credit facilities are available to the Company and the banks are obligated to fund and have been funding the Company under the terms of the facilities.

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

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

	March 31, 2015	December 31, 2014
(millions of Canadian dollars)		
Canadian financial institutions	**60**	58
United States financial institutions	**257**	240
European financial institutions	**60**	73
Other[1]	**160**	310
	537	681

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

As at March 31, 2015, the Company had provided letters of credit totalling $456 million in lieu of providing cash collateral to its counterparties pursuant to the terms of the relevant ISDA agreements. The Company held $28 million of cash collateral on derivative asset exposures as at March 31, 2015 and $33 million of cash collateral as at December 31, 2014.

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

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

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations.

Level 2

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

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

Level 3

Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The

Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. The Company does not have any other financial instruments categorized in Level 3.

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

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

March 31, 2015	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**-**	**10**	**-**	**10**
Interest rate contracts	**-**	**3**	**-**	**3**
Commodity contracts	**28**	**126**	**256**	**410**
Other contracts	**-**	**12**	**-**	**12**
	28	**151**	**256**	**435**
Long-term derivative assets				
Foreign exchange contracts	**-**	**85**	**-**	**85**
Interest rate contracts	**-**	**-**	**-**	**-**
Commodity contracts	**-**	**18**	**126**	**144**
Other contracts	**-**	**7**	**-**	**7**
	-	**110**	**126**	**236**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**-**	**(522)**	**-**	**(522)**
Interest rate contracts	**-**	**(684)**	**-**	**(684)**
Commodity contracts	**(19)**	**(117)**	**(162)**	**(298)**
	(19)	**(1,323)**	**(162)**	**(1,504)**
Long-term derivative liabilities				
Foreign exchange contracts	**-**	**(2,377)**	**-**	**(2,377)**
Interest rate contracts	**-**	**(974)**	**-**	**(974)**
Commodity contracts	**-**	**(139)**	**(227)**	**(366)**
	-	**(3,490)**	**(227)**	**(3,717)**
Total net financial asset/(liability)				
Foreign exchange contracts	**-**	**(2,804)**	**-**	**(2,804)**
Interest rate contracts	**-**	**(1,655)**	**-**	**(1,655)**
Commodity contracts	**9**	**(112)**	**(7)**	**(110)**
Other contracts	**-**	**19**	**-**	**19**
	9	**(4,552)**	**(7)**	**(4,550)**

December 31, 2014	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	-	13	-	13
Interest rate contracts	-	8	-	8
Commodity contracts	62	140	333	535
Other contracts	-	12	-	12
	62	173	333	568
Long-term derivative assets				
Foreign exchange contracts	-	51	-	51
Interest rate contracts	-	5	-	5
Commodity contracts	-	22	113	135
Other contracts	-	8	-	8
	-	86	113	199
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	-	(301)	-	(301)
Interest rate contracts	-	(438)	-	(438)
Commodity contracts	(28)	(137)	(116)	(281)
	(28)	(876)	(116)	(1,020)
Long-term derivative liabilities				
Foreign exchange contracts	-	(1,196)	-	(1,196)
Interest rate contracts	-	(576)	-	(576)
Commodity contracts	-	(125)	(181)	(306)
	-	(1,897)	(181)	(2,078)
Total net financial asset/(liability)				
Foreign exchange contracts	-	(1,433)	-	(1,433)
Interest rate contracts	-	(1,001)	-	(1,001)
Commodity contracts	34	(100)	149	83
Other contracts	-	20	-	20
	34	(2,514)	149	(2,331)

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

March 31, 2015	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	(2)	Forward gas price	2.83	4.52	3.58	\$/mmbtu[3]
NGL	35	Forward NGL price	0.23	1.45	1.11	\$/gallon
Power	(166)	Forward power price	30.75	71.50	48.76	\$/MWH
Commodity contracts - physical[1]						
Natural gas	(43)	Forward gas price	1.28	5.37	3.34	\$/mmbtu[3]
Crude	40	Forward crude price	34.77	116.05	62.04	\$/barrel
NGL	3	Forward NGL price	0.11	1.78	0.85	\$/gallon
Commodity options[2]						
Crude	42	Option volatility	20%	34%	25%	
NGL	84	Option volatility	18%	112%	36%	
	(7)					

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

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

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

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**149**	(164)
Total gains/(loss)		
Included in earnings[1]	**(7)**	12
Included in OCI	**2**	5
Settlements	**(151)**	14
Level 3 net derivative liability at end of period	**(7)**	(133)

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

The Company's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at March 31, 2015 or 2014.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The Company recognizes equity investments in other entities not categorized as held to maturity at fair value, with changes in fair value recorded in OCI, unless actively quoted prices are not available for fair value measurement in which case these investments are recorded at cost. The carrying value of all equity investments recognized at cost totalled $102 million as at March 31, 2015 (December 31, 2014 - $99 million).

The Company has a held to maturity preferred share investment carried at its amortized cost of $352 million as at March 31, 2015 (December 31, 2014 - $323 million). These preferred shares are entitled to a cumulative preferred dividend based on the average yield of Government of Canada bonds maturing in greater than 10 years plus a range of 4.3% to 4.4%. As at March 31, 2015, the fair value of this preferred share investment approximates its face value of $580 million (December 31, 2014 - $580 million).

As at March 31, 2015, the Company's long-term debt had a carrying value of $36,445 million (December 31, 2014 - $34,427 million) and a fair value of $39,489 million (December 31, 2014 - $36,637 million).

NET INVESTMENT HEDGES

The Company has designated a portion of its United States dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of its net investment in United States dollar denominated investments and subsidiaries.

During the three months ended March 31, 2015, the Company recognized an unrealized foreign exchange loss on the translation of United States dollar denominated debt of $331 million (2014 - unrealized loss of $57 million) and an unrealized loss on the change in fair value of its outstanding foreign exchange forward contracts of $124 million (2014 - unrealized loss of $49 million) in OCI. The Company also recognized a realized loss of $2 million (2014 - realized gain of $3 million) in OCI associated with the settlement of foreign exchange forward contracts that had matured during the period. There was no ineffectiveness during the three months ended March 31, 2015 (2014 - nil).

11. INCOME TAXES

The effective income tax rate for the three months ended March 31, 2015 was a recovery of 56.3% (2014 - 20.7% expense). The period-over-period change in the effective tax rate is primarily attributable to the rate-regulated tax benefit and other permanent items relative to the loss in the first three months of 2015. The effective income tax rate for the three months ended March 31, 2015 was further impacted by an out-of-period adjustment *(Note 3).*

12. RETIREMENT AND POSTRETIREMENT BENEFITS

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

NET BENEFIT COSTS RECOGNIZED

	Three months ended March 31,	
	2015	2014
(millions of Canadian dollars)		
Benefits earned during the period	**44**	30
Interest cost on projected benefit obligations	**27**	26
Expected return on plan assets	**(36)**	(32)
Amortization of prior service costs	**-**	-
Amortization of actuarial loss	**12**	7
Net benefit costs on an accrual basis[1,2]	**47**	31

1 *Included in net benefit costs for the three months ended March 31, 2015 are costs related to OPEB of $3 million (2014 - $4 million).*

2 *For the three months ended March 31, 2015, offsetting regulatory asset of nil (2014 - $2 million regulatory liability) has been recorded to the extent pension and OPEB costs are expected to be refunded to or collected from customers in future rates.*

13. CONTINGENCIES

ENBRIDGE ENERGY PARTNERS, L.P.

Enbridge holds an approximate 35.9% combined direct and indirect economic interest in EEP, which is consolidated with noncontrolling interests within the Sponsored Investments segment.

Lakehead System Lines 6A and 6B Crude Oil Releases

Line 6B Crude Oil Release

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

EEP continues to perform necessary remediation, restoration and monitoring of the areas affected by the Line 6B crude oil release. All the initiatives EEP is undertaking in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities. On March 14, 2013, EEP received an order from the Environmental Protection Agency (EPA) (the Order) which required additional containment and active recovery of submerged oil relating to the

Line 6B crude oil release. On February 12, 2015, the EPA approved the Submerged Oil Recovery and Assessment (SORA) work plan with modifications and acknowledged that EEP had completed the dredging requirements of the Order. At this time, EEP has completed all of the SORA.

Regulatory authority was transferred from the EPA to the Michigan Department of Environmental Quality (MDEQ). EEP is now working with the MDEQ who has oversight over the submerged oil reassessment, sheen management and sediment trap monitoring and maintenance activities through a Kalamazoo River Residual Oil Monitoring and Maintenance Work Plan.

As at March 31, 2015, EEP's total cost estimate for the Line 6B crude oil release remains at US$1.2 billion ($193 million after-tax attributable to Enbridge).

Expected losses associated with the Line 6B crude oil release included those costs that were considered probable and that could be reasonably estimated at March 31, 2015. Despite the efforts EEP has made to ensure the reasonableness of its estimates, there continues to be the potential for EEP to incur additional costs in connection with this crude oil release due to variations in any or all of the cost categories, including modified or revised requirements from regulatory agencies, in addition to fines and penalties and expenditures associated with litigation and settlement of claims.

Line 6A Crude Oil Release

A release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois on September 9, 2010. One claim related to the Line 6A crude oil release has been filed against Enbridge, EEP or their affiliates by the State of Illinois in the Illinois state court in connection with this crude oil release. On February 20, 2015, Enbridge, EEP and their affiliates agreed to a consent order releasing the parties from any claims, liability or penalties.

Insurance Recoveries

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

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

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

Enbridge has renewed its comprehensive property and liability insurance programs, which are effective May 1, 2015 through April 30, 2016 with a liability program aggregate limit of US$860 million, which includes sudden and accidental pollution liability. In the unlikely event 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. Approximately six actions or claims are pending against Enbridge, EEP or their affiliates in United States federal and state courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. 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.

As at March 31, 2015, included in EEP's estimated costs related to the Line 6B crude oil release is US$48 million in fines and penalties. Of this amount, US$40 million related to civil penalties under the Clean Water Act of the United States. While no final fine or penalty has been assessed or agreed to date, EEP believes that, based on the best information available at this time, the US$40 million represents an estimate of the minimum amount which may be assessed, excluding costs of injunctive relief that may be agreed to with the relevant governmental agencies. Given the complexity of settlement negotiations, which EEP expects will continue, and the limited information available to assess the matter, EEP is unable to reasonably estimate the final penalty which might be incurred or to reasonably estimate a range of outcomes at this time. Injunctive relief is likely to include further measures directed toward enhancing spill prevention, leak detection and emergency response to environmental events. The cost of compliance with such measures, when combined with any fine or penalty, could be material. Discussions with governmental agencies regarding fines, penalties and injunctive relief are ongoing.

TAX MATTERS

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

OTHER LITIGATION

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