Enbridge Inc.

Second Quarter

Interim Report to Shareholders
For the six months ended June 30, 2018

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

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-10934

ENBRIDGE INC.
(Exact Name of Registrant as Specified in Its Charter)

Canada	**None**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

200, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
(Address of Principal Executive Offices) (Zip Code)
(403) 231-3900
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
Emerging growth company ☐	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The registrant had 1,715,483,875 common shares outstanding as of July 27, 2018.

GLOSSARY

ALJ	Administrative Law Judge
AOCI	Accumulated other comprehensive income/(loss)
Army Corps	United States Army Corps of Engineers
ASU	Accounting Standards Update
Certificate	Certificate of Need
DRIP	Dividend Reinvestment and Share Purchase Plan
EBITDA	Earnings before interest, income taxes and depreciation and amortization
Eddystone Rail	Eddystone Rail Company, LLC
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
Enbridge	Enbridge Inc.
FERC	Federal Energy Regulatory Commission
IDRs	Incentive distribution rights
kbpd	thousands of barrels per day
Line 10	Line 10 crude oil pipeline
MNPUC	Minnesota Public Utilities Commission
MOLP	Midcoast Operating, L.P. and its subsidiaries
NGL	Natural gas liquids
OCI	Other comprehensive income/(loss)
OEB	Ontario Energy Board
Route Permit	Approved pipeline route for construction of the United States Line 3 Replacement Program
Sabal Trail	Sabal Trail Transmission, LLC
Seaway Pipeline	Seaway Crude Pipeline System
SEP	Spectra Energy Partners, LP
TCJA or United States Tax Reform	Tax Cuts and Jobs Act
the Court	United States District Court for the District of Columbia
the Fund Group	Enbridge Income Fund, Enbridge Commercial Trust, Enbridge Income Partners LP and the subsidiaries and investees of Enbridge Income Partners LP
the Merger Transaction	The stock-for-stock merger transaction on February 27, 2017 between Enbridge and Spectra Energy Corp
Union Gas	Union Gas Limited
U.S. L3R Program	United States Line 3 Replacement Program

CONVENTIONS

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to “dollars”, “$” or “C$” are to Canadian dollars and all references to “US$” are to United States dollars. All amounts are provided on a before tax basis, unless otherwise stated.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this quarterly report on Form 10-Q to provide information about us and our subsidiaries and affiliates, including management’s assessment of us and our 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”, “believe”, “estimate”, “expect”, “forecast”, “intend”, “likely”, “plan”, “project”, “target” 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 before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows; expected performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution, Green Power and Transmission, and Energy Services businesses; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners’ ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and expected timing thereof; estimated future dividends; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; expectations regarding the impact of the stock-for-stock merger transaction on February 27, 2017 between Enbridge and Spectra Energy Corp. (the Merger Transaction) including our combined scale, financial flexibility, growth program, future business prospects and performance; impact of the Canadian L3R Program on existing integrity programs; the sponsored vehicle strategy, including the proposed simplifications of our corporate structure; dividend payout policy; dividend growth and dividend payout expectation; expectations on impact of hedging program; and expectations resulting from the successful execution of our 2018-2020 Strategic Plan.

Although we believe 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; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of dispositions; the realization of anticipated benefits and synergies of the Merger Transaction; governmental legislation; acquisitions and the timing thereof; the success of integration plans; impact of the dividend policy on our future cash flows; credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to the impact of the Merger Transaction on us, expected EBITDA, earnings/(loss), earnings/(loss) per share, *or estimated future dividends. The most relevant assumptions associated with forward-looking statements on announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government and regulatory approvals on construction and in-service schedules and cost recovery regimes.*

Our forward-looking statements are subject to risks and uncertainties pertaining to the impact of the Merger Transaction, operating performance, regulatory parameters, dispositions, the proposed simplification of our corporate structure, dividend policy, project approval and support, renewals of rights-of-way, weather, economic and competitive conditions, public opinion, changes in tax laws and tax rates, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this quarterly report on Form 10-Q and in our 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 our 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 Inc. assumes no obligation to publicly update or revise any forward-looking statements made in this quarterly report on Form 10-Q or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(unaudited; millions of Canadian dollars, except per share amounts)				
Operating revenues				
Commodity sales	**6,451**	6,620	**13,719**	13,486
Gas distribution sales	**856**	847	**2,782**	2,210
Transportation and other services	**3,438**	3,649	**6,970**	6,566
Total operating revenues *(Note 3)*	**10,745**	11,116	**23,471**	22,262
Operating expenses				
Commodity costs	**6,278**	6,489	**13,275**	13,039
Gas distribution costs	**421**	429	**1,745**	1,444
Operating and administrative	**1,636**	1,646	**3,277**	3,197
Depreciation and amortization	**829**	868	**1,653**	1,540
Asset impairment *(Note 6)*	**10**	—	**1,072**	—
Total operating expenses	**9,174**	9,432	**21,022**	19,220
Operating income	**1,571**	1,684	**2,449**	3,042
Income from equity investments	**363**	236	**698**	472
Other income/(expense)				
Net foreign currency gain/(loss)	**(43)**	112	**(228)**	107
Other	**29**	67	**94**	107
Interest expense	**(690)**	(565)	**(1,346)**	(1,051)
Earnings before income taxes	**1,230**	1,534	**1,667**	2,677
Income tax recovery/(expense) *(Note 12)*	**97**	(293)	**170**	(491)
Earnings	**1,327**	1,241	**1,837**	2,186
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(167)**	(241)	**(143)**	(465)
Earnings attributable to controlling interests	**1,160**	1,000	**1,694**	1,721
Preference share dividends	**(89)**	(81)	**(178)**	(164)
Earnings attributable to common shareholders	**1,071**	919	**1,516**	1,557
Earnings per common share attributable to common shareholders *(Note 5)*	**0.63**	0.56	**0.90**	1.11
Diluted earnings per common share attributable to common shareholders *(Note 5)*	**0.63**	0.56	**0.90**	1.10

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(unaudited; millions of Canadian dollars)				
Earnings	**1,327**	1,241	**1,837**	2,186
Other comprehensive income/(loss), net of tax				
Change in unrealized gain/(loss) on cash flow hedges	**27**	(85)	**93**	(87)
Change in unrealized gain/(loss) on net investment hedges	**(99)**	171	**(283)**	220
Other comprehensive income from equity investees	**5**	2	**19**	8
Reclassification to earnings of loss on cash flow hedges	**36**	66	**73**	107
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**62**	3	**23**	7
Foreign currency translation adjustments	**1,047**	(1,443)	**2,626**	(1,011)
Other comprehensive income/(loss), net of tax	**1,078**	(1,286)	**2,551**	(756)
Comprehensive income/(loss)	**2,405**	(45)	**4,388**	1,430
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(297)**	15	**(444)**	(359)
Comprehensive income/(loss) attributable to controlling interests	**2,108**	(30)	**3,944**	1,071
Preference share dividends	**(89)**	(81)	**(178)**	(164)
Comprehensive income/(loss) attributable to common shareholders	**2,019**	(111)	**3,766**	907

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Six months ended June 30,	
	2018	2017
(unaudited; millions of Canadian dollars, except per share amounts)		
Preference shares		
Balance at beginning and end of period	**7,747**	7,255
Common shares		
Balance at beginning of period	**50,737**	10,492
Common shares issued in Merger Transaction	**—**	37,429
Dividend Reinvestment and Share Purchase Plan	**790**	538
Shares issued on exercise of stock options	**21**	45
Balance at end of period	**51,548**	48,504
Additional paid-in capital		
Balance at beginning of period	**3,194**	3,399
Stock-based compensation	**34**	51
Fair value of outstanding earned stock-based compensation from Merger Transaction	**—**	77
Options exercised	**(10)**	(53)
Enbridge Energy Company, Inc. common control transaction	**—**	118
Dilution loss on Enbridge Energy Partners, L.P. issuance of Class A units	**—**	(870)
Dilution gain on Spectra Energy Partners, LP restructuring *(Note 10)*	**1,136**	—
Dilution gains/(losses) and other	**(43)**	357
Balance at end of period	**4,311**	3,079
Deficit		
Balance at beginning of period	**(2,468)**	(716)
Earnings attributable to controlling interests	**1,694**	1,721
Preference share dividends	**(178)**	(164)
Common share dividends declared	**(1,145)**	(1,551)
Dividends paid to reciprocal shareholder	**17**	15
Modified retrospective adoption of accounting standard *(Note 2)*	**(86)**	—
Redemption value adjustment attributable to redeemable noncontrolling interests	**(483)**	189
Adjustment for the recognition of unutilized tax deductions for stock-based compensation expense	**—**	41
Balance at end of period	**(2,649)**	(465)
Accumulated other comprehensive income/(loss) *(Note 9)*		
Balance at beginning of period	**(973)**	1,058
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**2,250**	(650)
Balance at end of period	**1,277**	408
Reciprocal shareholding		
Balance at beginning and end of period	**(102)**	(102)
Total Enbridge Inc. shareholders' equity	**62,132**	58,679
Noncontrolling interests		
Balance at beginning of period	**7,597**	577
Earnings attributable to noncontrolling interests	**129**	371
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gain/(loss) on cash flow hedges	**6**	(19)
Foreign currency translation adjustments	**229**	(112)
Reclassification to earnings of loss on cash flow hedges	**15**	23
	250	(108)
Comprehensive income attributable to noncontrolling interests	**379**	263
Noncontrolling interests resulting from Merger Transaction	**—**	8,792
Enbridge Energy Company, Inc. common control transaction	**—**	(331)
Dilution gain on Enbridge Energy Partners, L.P. issuance of Class A units	**—**	870
Spectra Energy Partners, LP restructuring *(Note 10)*	**(1,486)**	—
Distributions	**(425)**	(386)
Contributions	**21**	453
Other	**14**	13
Balance at end of period	**6,100**	10,251
Total equity	**68,232**	68,930
Dividends paid per common share	**1.342**	1.193

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six months ended June 30, 2018	Six months ended June 30, 2017
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**1,837**	2,186
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**1,653**	1,540
Deferred income tax (recovery)/expense	**(328)**	416
Changes in unrealized (gain)/loss on derivative instruments, net *(Note 11)*	**549**	(898)
Earnings from equity investments	**(698)**	(472)
Distributions from equity investments	**732**	513
Asset impairment	**1,072**	—
(Gain)/loss on dispositions	**11**	(83)
Other	**110**	48
Changes in operating assets and liabilities	**1,600**	497
Net cash provided by operating activities	**6,538**	3,747
Investing activities		
Capital expenditures	**(3,243)**	(3,922)
Long-term investments	**(592)**	(2,778)
Distributions from equity investments in excess of cumulative earnings *(Note 7)*	**1,140**	39
Additions to intangible assets	**(425)**	(463)
Cash acquired in Merger Transaction	**—**	681
Proceeds from dispositions	**4**	442
Reimbursement of capital expenditures	**—**	212
Other	**(23)**	(40)
Net cash used in investing activities	**(3,139)**	(5,829)
Financing activities		
Net change in short-term borrowings	**(433)**	253
Net change in commercial paper and credit facility draws	**(2,166)**	1,773
Debenture and term note issues, net of issue costs	**3,537**	3,175
Debenture and term note repayments	**(2,147)**	(2,184)
Purchase of interest in consolidated subsidiary	**—**	(227)
Contributions from noncontrolling interests	**21**	453
Distributions to noncontrolling interests	**(425)**	(466)
Contributions from redeemable noncontrolling interests	**41**	600
Distributions to redeemable noncontrolling interests	**(174)**	(117)
Common shares issued	**14**	9
Preference share dividends	**(174)**	(164)
Common share dividends	**(1,493)**	(1,427)
Net cash provided by/(used in) financing activities	**(3,399)**	1,678
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**35**	(32)
Net increase/(decrease) in cash and cash equivalents and restricted cash	**35**	(436)
Cash and cash equivalents and restricted cash at beginning of period	**587**	1,562
Cash and cash equivalents and restricted cash at end of period	**622**	1,126

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2018	December 31, 2017
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**457**	480
Restricted cash	**165**	107
Accounts receivable and other	**6,100**	7,053
Accounts receivable from affiliates	**57**	47
Inventory	**1,205**	1,528
	7,984	9,215
Property, plant and equipment, net	**94,058**	90,711
Long-term investments	**16,391**	16,644
Restricted long-term investments	**286**	267
Deferred amounts and other assets	**6,498**	6,442
Intangible assets, net	**3,556**	3,267
Goodwill	**35,436**	34,457
Deferred income taxes	**1,227**	1,090
Total assets	**165,436**	162,093
Liabilities and equity		
Current liabilities		
Short-term borrowings	**1,014**	1,444
Accounts payable and other	**7,615**	9,478
Accounts payable to affiliates	**177**	157
Interest payable	**696**	634
Environmental liabilities	**32**	40
Current portion of long-term debt	**4,779**	2,871
	14,313	14,624
Long-term debt	**59,940**	60,865
Other long-term liabilities	**8,589**	7,510
Deferred income taxes	**9,929**	9,295
	92,771	92,294
Contingencies *(Note 14)*		
Redeemable noncontrolling interests	**4,433**	4,067
Equity		
Share capital		
Preference shares	**7,747**	7,747
Common shares *(1,715 and 1,695 outstanding at June 30, 2018 and December 31, 2017, respectively)*	**51,548**	50,737
Additional paid-in capital	**4,311**	3,194
Deficit	**(2,649)**	(2,468)
Accumulated other comprehensive income/(loss) *(Note 9)*	**1,277**	(973)
Reciprocal shareholding	**(102)**	(102)
Total Enbridge Inc. shareholders' equity	**62,132**	58,135
Noncontrolling interests	**6,100**	7,597
	68,232	65,732
Total liabilities and equity	**165,436**	162,093

See accompanying notes to the interim 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. ("we", "our", "us" and "Enbridge") have been prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP) and Regulation S-X for interim consolidated financial information. They do not include all of the information and notes required by U.S. GAAP for annual consolidated financial statements and should therefore be read in conjunction with our audited consolidated financial statements and notes for the year ended December 31, 2017 included in our Annual Report on Form 10-K. In the opinion of management, the interim consolidated financial statements contain all normal recurring adjustments necessary to present fairly our financial position, results of operations and cash flows for the interim periods reported. These interim consolidated financial statements follow the same significant accounting policies as those included in our annual consolidated financial statements for the year ended December 31, 2017 included in our Annual Report on Form 10-K, except for the adoption of new standards *(Note 2)*. Amounts are stated in Canadian dollars unless otherwise noted.

Our operations and earnings for interim periods can be affected by seasonal fluctuations within the gas distribution utility businesses, as well as other factors such as the supply of and demand for crude oil and natural gas, and may not be indicative of annual results.

Effective September 30, 2017, we combined Cash and cash equivalents and amounts previously presented as Bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements. As at December 31, 2017, $0.6 billion of Bank indebtedness has been combined within Cash and cash equivalents in our Consolidated Statements of Financial Position. Net cash provided by financing activities in our Consolidated Statements of Cash Flows for the six months ended June 30, 2017 has been reduced by $0.4 billion to reflect this change.

Certain comparative figures in our Consolidated Statement of Cash Flows have been reclassified to conform to the current year's presentation. In addition, activities for the six months ended June 30, 2017 relating to distributions to noncontrolling interests in relation to the stock-for-stock merger transaction on February 27, 2017 between Enbridge and Spectra Energy Corp (the Merger Transaction) have been reclassified, resulting in an increase to investing activities of $67 million and a decrease to financing activities of $67 million. Further, a subsidiary's debt repayment in the amount of $941 million during the three months ended June 30, 2017 has been reclassified within financing activities to conform to our current classification of such payments.

2. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

Effective January 1, 2018, we adopted Accounting Standards Update (ASU) 2018-02 to address a specific consequence of the Tax Cuts and Jobs Act (TCJA or United States Tax Reform) enacted by the United States federal government on December 22, 2017. The amendments in this accounting update allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA. The amendments will eliminate the stranded tax effects as a result of the reduction of the historical United States federal corporate income tax rate to the newly enacted United States federal corporate income tax rate. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation
Effective January 1, 2018, we adopted ASU 2017-09 and applied the standard on a prospective basis. The new standard was issued to clarify the scope of modification accounting. Under the new guidance, modification accounting is required for all changes to share-based payment awards, unless all of the following conditions are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The adoption of this accounting update did not, and is not expected to have a material impact on our consolidated financial statements.

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans
Effective January 1, 2018, we adopted ASU 2017-07 which was issued primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and other postretirement plans. Upon adoption of this accounting update, our Consolidated Statements of Earnings presents the current service cost within Operating and administrative expenses and the other components of net benefit cost within Other income/(expense). Previously, all components of net benefit cost were presented within Operating and administrative expenses. In addition, only the service cost component of net benefit cost will be capitalized on a prospective basis. The adoption of this accounting update did not, and is not expected to have a material impact on our consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets
Effective January 1, 2018, we adopted ASU 2017-05 on a modified retrospective basis. The new standard clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows
Effective January 1, 2018, we adopted ASU 2016-18 on a retrospective basis. The new standard clarifies guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows. The amendments require that changes in restricted cash and restricted cash equivalents be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. For current and comparative periods, we amended the presentation in the Consolidated Statements of Cash Flows to include restricted cash and restricted cash equivalents with cash and cash equivalents.

Simplifying Cash Flow Classification
Effective January 1, 2018, we adopted ASU 2016-15 on a retrospective basis. The new standard reduces diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statements of Cash Flows. The new guidance addresses eight specific presentation issues. We assessed each of the eight specific presentation issues and the adoption of this ASU did not have a material impact on our consolidated financial statements.

Recognition and Measurement of Financial Assets and Liabilities

Effective January 1, 2018, we adopted ASU 2016-01 on a prospective basis. The new standard addresses certain aspects of recognition, measurement, presentation and disclosure of financial assets and liabilities. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative and are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial assets and liabilities is measured using the exit price notion. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Revenue from Contracts with Customers

Effective January 1, 2018, we adopted ASU 2014-09 on a modified retrospective basis to contracts that were not complete at the date of initial application. The new standard was issued with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the previous standards.

In adopting Accounting Standards Codification (ASC) 606, we applied the practical expedient for contract modifications whereby contracts that were modified before January 1, 2018 were not retrospectively restated. Instead, the aggregate effect of all contract modifications occurring before that time has been reflected when identifying satisfied and unsatisfied performance obligations, determining the transaction price and allocating the transaction price to satisfied and unsatisfied performance obligations.

Revenue was previously recognized for a certain contract within the Liquids Pipelines business unit using a formula-based method. Under the new revenue standard, revenue is recognized on a straight-line basis over the term of the agreement in order to reflect the fulfillment of our performance obligation to provide up to a specified volume of pipeline capacity throughout the term of the contract.

Certain payments received from customers to offset the cost of constructing assets required to provide services to those customers, referred to as Contributions in Aid of Construction (CIACs) were previously recorded as reductions of property, plant and equipment regardless of whether the amounts were imposed by regulation or arose from negotiations with customers. Under the new revenue standard, CIACs which are negotiated as part of an agreement to provide transportation and other services to a customer are deemed to be advance payments for future services and are recognized as revenue when those future services are provided. Accordingly, negotiated CIACs are accounted for as deferred revenue and recognized as revenue over the term of the associated revenue contract. Amounts which are required to be collected from the customer based on requirements of the regulator continue to be accounted for as reductions of property, plant and equipment.

The below table presents the cumulative, immaterial effect of the adoption of ASC 606 on our Consolidated Statement of Financial Position as at January 1, 2018 on each affected financial statement line item along with explanations of those effects. For the three and six months ended June 30, 2018, the effect of the adoption of ASC 606 on our Consolidated Statement of Earnings was not material.

	Balance at December 31, 2017	Adjustments Due to ASC 606	Balance at January 1, 2018
(millions of Canadian dollars)			
Assets			
Deferred amounts and other assets	6,442	(170)	6,272
Property, plant and equipment, net	90,711	112	90,823
Liabilities and equity			
Accounts payable and other	9,478	62	9,540
Other long-term liabilities	7,510	66	7,576
Deferred income taxes	9,295	(62)	9,233
Redeemable noncontrolling interests	4,067	(38)	4,029
Deficit	(2,468)	(86)	(2,554)

FUTURE ACCOUNTING POLICY CHANGES

Improvements to Accounting for Hedging Activities

ASU 2017-12 was issued in August 2017 with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The amendments allow cash flow hedging of contractually specified components in financial and non-financial items. Under the new guidance, hedge ineffectiveness is no longer required to be measured and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The ASU also allows the initial quantitative hedge effectiveness assessment to be performed at any time before the end of the quarter in which the hedge is designated. After initial quantitative testing is performed, an ongoing qualitative effectiveness assessment is permitted. The accounting update is effective January 1, 2019, with early adoption permitted, and is to be applied on a modified retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

Amending the Amortization Period for Certain Callable Debt Securities Purchased at a Premium

ASU 2017-08 was issued in March 2017 with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The accounting update is effective January 1, 2019 and will be applied on a modified retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity will recognize as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. The accounting update is effective January 1, 2020. We are currently assessing the impact of the new standard on our consolidated financial statements.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We will adopt the new standard on January 1, 2019 and we intend to apply the transition practical expedients offered in connection with this update. The election to apply the package of practical expedients allows an entity to not apply the new lease standard to the prior year comparative periods in the year of adoption. Application of the package of practical expedients permits entities not to reassess whether any expired or existing contracts contain leases, their lease classification, as well as any related initial direct costs.

Further, ASU 2018-01 was issued in January 2018 to address stakeholder concerns about the costs and complexity of complying with the transition provisions of the new lease requirements as they relate to land easements. The amendments provide an optional transition practical expedient to not evaluate existing or expired land easements that were not previously accounted for as leases under existing guidance. We intend to elect this practical expedient in connection with the adoption of the new lease requirements.

We have substantially completed the process of identifying existing lease contracts and are currently performing detailed evaluations of our leases under the new accounting requirements. We believe the most significant changes to our financial statements relate to the recognition of a lease liability and offsetting right-of-use asset in our consolidated balance sheet for operating leases. We continue to assess the necessary changes to accounting and business processes in order to implement the recognition and disclosure requirements of the new lease standard.

3. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Products and Services

Three months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	2,079	958	151	—	—	—	**3,188**
Storage and other revenue	42	51	52	—	—	—	**145**
Gas gathering and processing revenue	—	231	—	—	—	—	**231**
Gas distribution revenue	—	—	856	—	—	—	**856**
Electricity and transmission revenue	—	—	—	148	—	—	**148**
Commodity sales	—	639	—	—	—	—	**639**
Total revenue from contracts with customers	2,121	1,879	1,059	148	—	—	**5,207**
Commodity sales	—	—	—	—	5,812	—	**5,812**
Other revenue[1]	(261)	(17)	9	1	—	(6)	**(274)**
Intersegment revenue	90	2	2	—	24	(118)	**—**
Total revenue	**1,950**	**1,864**	**1,070**	**149**	**5,836**	**(124)**	**10,745**

Six months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	4,137	1,910	390	—	—	—	**6,437**
Storage and other revenue	82	111	118	—	—	—	**311**
Gas gathering and processing revenue	—	436	—	—	—	—	**436**
Gas distribution revenue	—	—	2,782	—	—	—	**2,782**
Electricity and transmission revenue	—	—	—	302	—	—	**302**
Commodity sales	—	1,332	—	—	—	—	**1,332**
Total revenue from contracts with customers	4,219	3,789	3,290	302	—	—	**11,600**
Commodity sales	—	—	—	—	12,387	—	**12,387**
Other revenue[1]	(530)	8	11	4	—	(9)	**(516)**
Intersegment revenue	170	4	6	—	81	(261)	**—**
Total revenue	**3,859**	**3,801**	**3,307**	**306**	**12,468**	**(270)**	**23,471**

1 Includes mark-to-market gains/(losses) from our hedging program.

We disaggregate revenue into categories which represent our principal performance obligations within each business segment because these revenue categories represent the most significant revenue streams in each segment and consequently are considered to be the most relevant revenue information for management to consider in evaluating performance.

Contract Balances

	Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at January 1, 2018	2,475	290	992
Balance as at June 30, 2018	2,086	295	1,097

Contract assets represent the amount of revenue which has been recognized in advance of payments received for performance obligations we have fulfilled (or partially fulfilled) and prior to the point in time at which our right to the payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to the consideration becomes unconditional.

Contract liabilities represent payments received for performance obligations which have not been fulfilled. Contract liabilities primarily relate to make-up rights and deferred revenue. Revenue recognized during the three and six months ended June 30, 2018 included in contract liabilities at the beginning of the period is $29 million and $124 million, respectively. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the three and six months ended June 30, 2018 were $103 million and $198 million, respectively.

Performance Obligations

Segment	Nature of Performance Obligation
Liquids Pipelines	• Transportation and storage of crude oil and natural gas liquids (NGL)
Gas Transmission and Midstream	• Sale of crude oil, natural gas and NGLs • Transportation, storage, gathering, compression and treating of natural gas • Transportation of NGLs
Gas Distribution	• Supply and delivery of natural gas • Transportation of natural gas • Storage of natural gas
Green Power and Transmission	• Generation and transmission of electricity • Delivery of electricity from renewable energy generation facilities

There was no material revenue recognized in the three and six months ended June 30, 2018 from performance obligations satisfied in previous periods.

Payment Terms

Payments are received monthly from customers under long-term transportation, commodity sales, and gas gathering and processing contracts. Payments from Gas Distribution customers are received on a continuous basis based on established billing cycles.

Certain contracts in the United States offshore business provide for us to receive a series of fixed monthly payments (FMPs) for a specified period which is less than the period during which the performance obligations are satisfied. As a result, a portion of the FMPs is recorded as a contract liability. The FMPs are not considered to be a financing arrangement because the payments are scheduled to match the production profiles of offshore oil and gas fields, which generate greater revenue in the initial years of their productive lives.

Revenue to be Recognized from Unfulfilled Performance Obligations

Total revenue from performance obligations expected to be fulfilled in future periods is $65.7 billion, of which $3.5 billion and $6.0 billion is expected to be recognized during the six months ending December 31, 2018 and year ending December 31, 2019, respectively.

The revenues excluded from the amounts above based on optional exemptions available under ASC 606, as explained below, represent a significant portion of our overall revenues and revenues from contracts with customers. Certain revenues such as flow-through operating costs charged to shippers are recognized at the amount for which we have the right to invoice our customers and are excluded from the amounts for revenue to be recognized in the future from unfulfilled performance obligations above. Variable consideration is excluded from the amounts above due to the uncertainty of the associated consideration, which is generally resolved when actual volumes and prices are determined. For example, we consider interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. Additionally, the effect of escalation on certain tolls which are contractually escalated for inflation has not been reflected in the amounts above as it is not possible to reliably estimate future inflation rates. Revenues for periods extending beyond the current rate settlement term for regulated contracts where the tolls are periodically reset by the regulator are excluded from the amounts above since future tolls remain unknown. Finally, revenues from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

SIGNIFICANT JUDGMENTS MADE IN RECOGNIZING REVENUE

Long-Term Transportation Agreements

For long-term transportation agreements, significant judgments pertain to the period over which revenue is recognized and whether the agreement provides for make-up rights for the shippers. Transportation revenue earned from firm contracted capacity arrangements is recognized ratably over the contract period. Transportation revenue from interruptible or volumetric-based arrangements is recognized when services are performed.

Estimates of Variable Consideration

Revenue from arrangements subject to variable consideration is recognized only to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur when the uncertainty associated with the variable consideration is subsequently resolved. Uncertainties associated with variable consideration relate principally to differences between estimated and actual volumes and prices. These uncertainties are resolved each month when actual volumes are sold or transported and actual tolls and prices are determined.

Recognition and Measurement of Revenue

Three months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenue from products transferred at a point in time[1]	—	639	20	—	—	**659**
Revenue from products and services transferred over time[2]	2,121	1,240	1,039	148	—	**4,548**
Total revenue from contracts with customers	**2,121**	**1,879**	**1,059**	**148**	**—**	**5,207**

Six months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenue from products transferred at a point in time[1]	—	1,332	45	—	—	**1,377**
Revenue from products and services transferred over time[2]	4,219	2,457	3,245	302	—	**10,223**
Total revenue from contracts with customers	**4,219**	**3,789**	**3,290**	**302**	**—**	**11,600**

1 *Revenue from sales of crude oil, natural gas and NGLs.*

2 *Revenue from crude oil and natural gas pipeline transportation, storage, natural gas gathering, compression and treating, natural gas distribution, natural gas storage services and electricity sales.*

Performance Obligations Satisfied at a Point in Time

Revenue from commodity sales where the commodity is not immediately consumed prior to use is recognized at the point in time when the contractually specified volume of the commodity has been delivered, as control over the commodity transfers to the customer upon delivery.

Performance Obligations Satisfied Over Time

For arrangements involving the transportation and sale of petroleum products and natural gas where the transportation services or commodities are simultaneously received and consumed by the shipper or customer, we recognize revenue over time using an output method based on volumes of commodities delivered or transported. The measurement of the volumes transported or delivered corresponds directly to the benefits received by the shippers or customers during that period.

Determination of Transaction Prices

Prices for gas processing and transportation services are determined based on the capital cost of the facilities, pipelines and associated infrastructure required to provide such services plus a rate of return on capital invested that is determined either through negotiations with customers or through regulatory processes for those operations that are subject to rate regulation.

Prices for commodities sold are determined by reference to market price indices plus or minus a negotiated differential and in certain cases a marketing fee.

Prices for natural gas sold and distribution services provided by regulated natural gas distribution operations are prescribed by regulation.

4. SEGMENTED INFORMATION

Effective December 31, 2017, we changed our segment-level profit measure to Earnings before interest, income taxes, and depreciation and amortization from the previous measure of Earnings before interest and income taxes. We also renamed the Gas Pipelines and Processing segment to Gas Transmission and Midstream. The presentation of the prior year tables have been revised in order to align with the current presentation.

Three months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**1,950**	**1,864**	**1,070**	**149**	**5,836**	**(124)**	**10,745**
Commodity and gas distribution costs	**(5)**	**(591)**	**(444)**	**—**	**(5,784)**	**125**	**(6,699)**
Operating and administrative	**(714)**	**(534)**	**(271)**	**(36)**	**(21)**	**(60)**	**(1,636)**
Asset impairment	**(10)**	**—**	**—**	**—**	**—**	**—**	**(10)**
Income/(loss) from equity investments	**137**	**229**	**(10)**	**4**	**3**	**—**	**363**
Other income/(expense)	**(36)**	**46**	**25**	**9**	**1**	**(59)**	**(14)**
Earnings/(loss) before interest, income taxes, and depreciation and amortization	**1,322**	**1,014**	**370**	**126**	**35**	**(118)**	**2,749**
Depreciation and amortization							**(829)**
Interest expense							**(690)**
Income tax recovery							**97**
Earnings							**1,327**
Capital expenditures[1]	**510**	**867**	**239**	**10**	**—**	**2**	**1,628**

Three months ended June 30, 2017	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	2,243	1,954	1,022	140	5,855	(98)	11,116
Commodity and gas distribution costs	(5)	(703)	(452)	2	(5,862)	102	(6,918)
Operating and administrative	(684)	(553)	(241)	(41)	(11)	(116)	(1,646)
Income/(loss) from equity investments	108	155	(23)	—	—	(4)	236
Other income/(expense)	(5)	79	4	—	1	100	179
Earnings/(loss) before interest, income taxes, and depreciation and amortization	1,657	932	310	101	(17)	(16)	2,967
Depreciation and amortization							(868)
Interest expense							(565)
Income tax expense							(293)
Earnings							1,241
Capital expenditures[1]	540	1,374	309	115	1	9	2,348

Six months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**3,859**	**3,801**	**3,307**	**306**	**12,468**	**(270)**	**23,471**
Commodity and gas distribution costs	**(9)**	**(1,211)**	**(1,832)**	**—**	**(12,239)**	**271**	**(15,020)**
Operating and administrative	**(1,461)**	**(1,041)**	**(519)**	**(66)**	**(33)**	**(157)**	**(3,277)**
Asset impairment	**(154)**	**(913)**	**—**	**—**	**—**	**(5)**	**(1,072)**
Income/(loss) from equity investments	**268**	**437**	**7**	**(21)**	**7**	**—**	**698**
Other income/(expense)	**(25)**	**67**	**43**	**16**	**1**	**(236)**	**(134)**
Earnings/(loss) before interest, income taxes, and depreciation and amortization	**2,478**	**1,140**	**1,006**	**235**	**204**	**(397)**	**4,666**
Depreciation and amortization							**(1,653)**
Interest expense							**(1,346)**
Income tax recovery							**170**
Earnings							**1,837**
Capital expenditures[1]	**1,125**	**1,692**	**422**	**24**	**—**	**8**	**3,271**

Six months ended June 30, 2017	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	4,398	3,189	2,606	277	11,988	(196)	22,262
Commodity and gas distribution costs	(8)	(1,350)	(1,498)	3	(11,830)	200	(14,483)
Operating and administrative	(1,444)	(807)	(430)	(81)	(23)	(412)	(3,197)
Income from equity investments	194	265	13	2	2	(4)	472
Other income/(expense)	(3)	110	6	1	2	98	214
Earnings/(loss) before interest, income taxes, and depreciation and amortization	3,137	1,407	697	202	139	(314)	5,268
Depreciation and amortization							(1,540)
Interest expense							(1,051)
Income tax expense							(491)
Earnings							2,186
Capital expenditures[1]	1,194	2,029	492	229	1	68	4,013

1 Includes allowance for equity funds used during construction.

TOTAL ASSETS

	June 30, 2018	December 31, 2017
(millions of Canadian dollars)		
Liquids Pipelines	**65,740**	63,881
Gas Transmission and Midstream	**62,693**	60,745
Gas Distribution	**25,581**	25,956
Green Power and Transmission	**6,239**	6,289
Energy Services	**1,993**	2,514
Eliminations and Other	**3,190**	2,708
	165,436	162,093

5. EARNINGS PER COMMON SHARE

BASIC

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 our pro-rata weighted average interest in our own common shares of 13 million for the three and six months ended June 30, 2018 and 2017, resulting from our reciprocal investment in Noverco Inc.

DILUTED

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.

Weighted average shares outstanding used to calculate basic and diluted earnings per share are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(number of common shares in millions)				
Weighted average shares outstanding	**1,695**	1,628	**1,690**	1,404
Effect of dilutive options	**3**	8	**3**	9
Diluted weighted average shares outstanding	**1,698**	1,636	**1,693**	1,413

For the three months ended June 30, 2018 and 2017, 30,245,645 and 13,416,763, respectively, of anti-dilutive stock options with a weighted average exercise price of $49.67 and $57.98, respectively, were excluded from the diluted earnings per common share calculation.

For the six months ended June 30, 2018 and 2017, 30,063,894 and 13,480,978, respectively, of anti-dilutive stock options with a weighted average exercise price of $49.73 and $57.84, respectively, were excluded from the diluted earnings per common share calculation.

6. DISPOSITIONS

ASSETS HELD FOR SALE
Midcoast Operating, L.P.
On May 9, 2018, our indirect subsidiary, Enbridge (U.S.) Inc. entered into a definitive agreement to sell Midcoast Operating, L.P. and its subsidiaries (collectively, MOLP) to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC) for a cash purchase price of approximately US$1.1 billion, subject to customary closing adjustments.

On August 1, 2018, Enbridge (U.S.) Inc. closed the sale of MOLP for total cash proceeds of approximately US$1.1 billion less deposits and other customary closing items. MOLP conducted our United States natural gas and natural gas liquids gathering, processing, transportation and marketing businesses, and was a part of our Gas Transmission and Midstream segment.

As at December 31, 2017, the MOLP assets, excluding our equity method investment in the Texas Express NGL pipeline system, were classified as held for sale and were measured at the lower of their carrying value or fair value less costs to sell.

In the first quarter of 2018, as a result of entering into a definitive sales agreement, the fair value of the assets held for sale as at March 31, 2018 were revised based on the sale price. Accordingly, we recorded a loss of $913 million ($701 million after-tax). This loss has been included within Asset impairment on the Consolidated Statements of Earnings for the six months ended June 30, 2018.

In the second quarter of 2018, our equity method investment in the Texas Express NGL pipeline system, together with the MOLP assets, also met the conditions for assets held for sale. The $447 million carrying value of Texas Express NGL pipeline system equity investment and an allocated goodwill of $262 million, were included within the disposal group as at June 30, 2018 and subsequently disposed on August 1, 2018.

Line 10 Crude Oil Pipeline
In the first quarter of 2018, we satisfied the condition as set out in our agreements for the sale of our Line 10 crude oil pipeline (Line 10), which originates near Hamilton, Ontario and terminates at West Seneca, New York. Our subsidiaries, Enbridge Pipelines Inc. and Enbridge Energy Partners, L.P., own the Canadian and United States portions of Line 10, respectively, and the related assets are included in our Liquids Pipeline segment.

We expect to close the sale of Line 10 within one year, subject to regulatory approval and certain closing conditions. As such, during the first quarter of 2018, we classified Line 10 assets as held for sale and measured them at the lower of their carrying value or fair value less costs to sell, which resulted in a loss of $154 million ($95 million after-tax attributable to us) included within Asset impairment on the Consolidated Statements of Earnings for the six months ended June 30, 2018.

The table below summarizes the presentation of net assets held for sale in our Consolidated Statements of Financial Position:

	June 30, 2018	December 31, 2017
(millions of Canadian dollars)		
Accounts receivable and other (current assets held for sale)	**363**	424
Deferred amounts and other assets (long-term assets held for sale)	**1,186**	1,190
Accounts payable and other (current liabilities held for sale)	**(348)**	(315)
Other long-term liabilities (long-term liabilities held for sale)	**(43)**	(34)
Net assets held for sale	**1,158**	1,265

OTHER

Canadian Natural Gas Gathering and Processing Businesses

On July 4, 2018, we entered into agreements with Brookfield Infrastructure Partners L.P. and its institutional partners to sell our Canadian natural gas gathering and processing businesses for a cash purchase price of approximately $4.31 billion, subject to customary closing adjustments and receipt of regulatory approvals. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations. The sale of the provincially regulated facilities is expected to close in 2018 for proceeds of approximately $2.5 billion and the sale of the federally regulated facilities is expected to close in mid-2019 for proceeds of approximately $1.8 billion.

Renewable Energy Generation Assets

On May 9, 2018, we entered into agreements with the Canadian Pension Plan Investment Board (CPPIB) to sell a 49% interest in all of our Canadian renewable energy generation assets, 49% of two large United States renewable assets and 49% of our interest in the Hohe See Offshore wind farm and its subsequent expansion, both concurrently under construction in Germany, (collectively, the Renewable Assets). Proceeds from the transaction are approximately $1.75 billion. In addition, CPPIB will fund their pro-rata share of the remaining capital expenditures on the Hohe See Offshore wind project. We will maintain a 51% interest in the Renewable Assets and continue to manage, operate and provide administrative services for these assets.

On August 1, 2018, we closed the sale of the Renewable Assets for total cash proceeds of $1.75 billion less customary closing items. These assets were a part of our Green Power and Transmission segment.

Also during the second quarter of 2018, a deferred income tax recovery of $258 million ($190 million attributable to us) was recorded in the three and six months ended June 30, 2018 as a result of the agreement entered into for the Renewable Assets *(Note 12)*.

7. VARIABLE INTEREST ENTITIES

Spectra Energy Partners, LP (SEP) owns a 50% interest in Sabal Trail Transmission, LLC (Sabal Trail), a joint venture that operates a pipeline originating in Alabama that transports natural gas to Florida and has been classified as a variable interest entity.

On April 30, 2018, Sabal Trail issued US$500 million in aggregate principal amount of 4.246% senior notes due in 2028, US$600 million in aggregate principal amount of 4.682% senior notes due in 2038 and US$400 million in aggregate principal amount of 4.832% senior notes due in 2048. Sabal Trail distributed net proceeds from the offering to the partners as a partial reimbursement of construction and development costs incurred by the partners. The net distribution made to SEP was US$744 million and was used to pay down indebtedness and is included within Distributions from equity investments in excess of cumulative earnings on the Consolidated Statement of Cash Flows for the six months ended June 30, 2018.

As at June 30, 2018, Sabal Trail is no longer a variable interest entity due to sufficient equity at risk to finance its activities based on reconsideration events related to Sabal Trail's debt issuance and the distributions made to its partners.

8. DEBT

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at June 30, 2018:

		June 30, 2018		
	Maturity	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.[2]	2019-2022	**6,537**	**1,761**	**4,776**
Enbridge (U.S.) Inc.	2019	**1,861**	**456**	**1,405**
Enbridge Energy Partners, L.P.[3]	2019-2022	**3,453**	**2,261**	**1,192**
Enbridge Gas Distribution Inc. (EGD)	2019	**1,017**	**794**	**223**
Enbridge Income Fund	2020	**1,500**	**351**	**1,149**
Enbridge Pipelines Inc.	2019	**3,000**	**1,906**	**1,094**
Spectra Energy Partners, LP[4]	2022	**3,289**	**1,528**	**1,761**
Union Gas Limited (Union Gas)	2021	**700**	**230**	**470**
Total committed credit facilities		**21,357**	**9,287**	**12,070**

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

2 Includes $135 million, $164 million (US$125 million) and $150 million of commitments that expire in 2018, 2018 and 2020, respectively.

3 Includes $230 million (US$175 million) and $243 million (US$185 million) of commitments that expire in 2018 and 2020, respectively.

4 Includes $443 million (US$336 million) of commitments that expire in 2021.

During the second quarter of 2018, Enbridge (U.S.) Inc. terminated a US$500 million credit facility, which was set to mature in 2019, and repaid drawn amounts. In addition, an unutilized Enbridge US$100 million credit facility expired.

During the first quarter of 2018, Enbridge terminated a US$650 million credit facility, which was set to mature in 2019, and repaid drawn amounts. In addition, Enbridge (U.S.) Inc. terminated an unutilized US$950 million credit facility, which was set to mature in 2019.

During the first quarter of 2018, Westcoast Energy Inc. terminated an unutilized $400 million credit facility with a syndicate of banks. The facility was acquired in conjunction with the Merger Transaction and was set to mature in 2021.

In addition to the committed credit facilities noted above, we maintain $796 million of uncommitted demand credit facilities, of which $517 million were unutilized as at June 30, 2018. As at December 31, 2017, we had $792 million of uncommitted credit facilities, of which $518 million were unutilized.

Our 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 we have the option to extend such facilities, which are currently set to mature from 2019 to 2022.

As at June 30, 2018 and December 31, 2017, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year of $7,862 million and $10,055 million, respectively, were supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the six months ended June 30, 2018, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.			
	March 2018	Fixed-to-floating rate notes due 2078[1]	US$850
	April 2018	Fixed-to-floating rate notes due 2078[2]	$750
	April 2018	Fixed-to-floating rate notes due 2078[3]	US$600
Spectra Energy Partners, LP[4]			
	January 2018	3.50% senior notes due 2028	US$400
	January 2018	4.15% senior notes due 2048	US$400

1 Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.25%. Subsequently, the interest rate will be set to equal the three-month London Interbank Offered Rate (LIBOR) plus a margin of 364 basis points from years 10 to 30, and a margin of 439 basis points from years 30 to 60.

2 Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.625%. Subsequently, the interest rate will be set to equal the Canadian Dollar Offered Rate plus a margin of 432 basis points from years 10 to 30, and a margin of 507 basis points from years 30 to 60.

3 Notes mature in 60 years and are callable on or after year five. For the initial five years, the notes carry a fixed interest rate of 6.375%. Subsequently, the interest rate will be set to equal the three-month LIBOR plus a margin of 359 basis points from years five to 10, a margin of 384 basis points from years 10 to 25, and a margin of 459 basis points from years 25 to 60.

4 Issued through Texas Eastern Transmission, LP, a wholly-owned operating subsidiary of SEP.

LONG-TERM DEBT REPAYMENTS

During the six months ended June 30, 2018, we completed the following long-term debt repayments:

Company	Retirement/Repayment Date		Principal Amount	Cash Consideration[1]
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Energy Partners, L.P.				
	April 2018	6.50% senior notes	US$400	
Enbridge Pipelines (Southern Lights) L.L.C				
	June 2018	3.98% medium-term notes due June 2040	US$20	
Enbridge Southern Lights LP				
	January 2018	4.01% medium-term notes due June 2040	$9	
Spectra Energy Capital, LLC				
Repurchase via Tender Offer[2]				
	March 2018	6.75% senior unsecured notes due 2032	US$64	US$80
	March 2018	7.50% senior unsecured notes due 2038	US$43	US$59
Redemption[2]				
	March 2018	5.65% senior unsecured notes due 2020	US$163	US$172
	March 2018	3.30% senior unsecured notes due 2023	US$498	US$508
Repayment				
	April 2018	6.20% senior notes	US$272	
Union Gas Limited				
	April 2018	5.35% medium-term notes	$200	
Westcoast Energy Inc.				
	May 2018	6.90% senior secured notes	$13	
	May 2018	4.34% senior secured notes	$4	

1 Cash consideration disclosed for repayments where the cash paid differs from the principal amount.

2 The loss on debt extinguishment of $37 million (US$29 million), net of the fair value adjustment recorded upon completion of the Merger Transaction, was reported within Interest expense in the Consolidated Statements of Earnings.

FAIR VALUE ADJUSTMENT

As at June 30, 2018, the net fair value adjustment for total debt assumed in the Merger Transaction was $1,015 million. During the three and six months ended June 30, 2018, the amortization of the fair value adjustment, recorded as a reduction to Interest expense in the Consolidated Statements of Earnings, was $26 million and $88 million, respectively.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at June 30, 2018, we were in compliance with all debt covenants.

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated other comprehensive income (AOCI) attributable to our common shareholders for the six months ended June 30, 2018 and 2017 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance as at January 1, 2018	**(644)**	**(139)**	**77**	**10**	**(277)**	**(973)**
Other comprehensive income/(loss) retained in AOCI	**100**	**(328)**	**2,354**	**3**	**—**	**2,129**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**67**	**—**	**—**	**—**	**—**	**67**
Commodity contracts[2]	**(1)**	**—**	**—**	**—**	**—**	**(1)**
Foreign exchange contracts[3]	**5**	**—**	**—**	**—**	**—**	**5**
Other contracts[4]	**3**	**—**	**—**	**—**	**—**	**3**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**—**	**—**	**—**	**—**	**31**	**31**
	174	**(328)**	**2,354**	**3**	**31**	**2,234**
Tax impact						
Income tax on amounts retained in AOCI	**(13)**	**45**	**—**	**10**	**—**	**42**
Income tax on amounts reclassified to earnings	**(18)**	**—**	**—**	**—**	**(8)**	**(26)**
	(31)	**45**	**—**	**10**	**(8)**	**16**
Balance as at June 30, 2018	**(501)**	**(422)**	**2,431**	**23**	**(254)**	**1,277**

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance as at January 1, 2017	(746)	(629)	2,700	37	(304)	1,058
Other comprehensive income/(loss) retained in AOCI	(44)	222	(899)	3	—	(718)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	71	—	—	—	—	71
Commodity contracts[2]	(4)	—	—	—	—	(4)
Foreign exchange contracts[3]	2	—	—	—	—	2
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	10	10
	25	222	(899)	3	10	(639)
Tax impact						
Income tax on amounts retained in AOCI	12	(2)	—	5	—	15
Income tax on amounts reclassified to earnings	(23)	—	—	—	(3)	(26)
	(11)	(2)	—	5	(3)	(11)
Balance as at June 30, 2017	(732)	(409)	1,801	45	(297)	408

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

10. NONCONTROLLING INTERESTS

As at December 31, 2017, we collectively owned a 75% ownership interest in SEP, together with 100% of SEP's incentive distribution rights (IDRs). On January 22, 2018, Enbridge and SEP announced the execution of a definitive agreement, resulting in us converting all of our IDRs and general partner economic interests in SEP into 172.5 million newly issued SEP common units. As part of the transaction, all of the IDRs were eliminated. We now hold a non-economic general partner interest in SEP and own approximately 403 million SEP common units, representing approximately 83% of SEP's outstanding common units. As a result of this restructuring, we recorded a decrease in Noncontrolling interests of $1.5 billion and increases in Additional paid-in capital and Deferred income taxes of $1.1 billion and $333 million, respectively, for the six months ended June 30, 2018.

11. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

Our earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and our 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 we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

We generate certain revenues, incur expenses, and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments are used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. We hedge certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk

Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.6%.

As a result of the Merger Transaction, we are exposed to changes in the fair value of fixed rate debt that arise as a result of the changes in market interest rates. Pay floating-receive fixed interest rate swaps are used to hedge against future changes to the fair value of fixed rate debt. We have assumed a program within our subsidiaries to mitigate the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps with an average swap rate of 2.2%.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have assumed a program within some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 3.1%.

We also monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk.

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

Emission Allowance Price Risk
Emission allowance price risk is the risk of gain or loss due to changes in the market price of emission allowances that our gas distribution business is required to purchase for itself and most of its customers to meet greenhouse gas compliance obligations under the Ontario Cap and Trade program. Similar to the gas supply procurement framework, the Ontario Energy Board's (OEB) framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates, subject to OEB approval.

Equity Price Risk
Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our 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. We use equity derivatives to manage the earnings volatility derived from one form of stock-based compensation, restricted share units. We use 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 our derivative instruments.

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial 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 events, and reduces our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances. The following table summarizes the maximum potential settlement in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

June 30, 2018	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value 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	**—**	**2**	**—**	**72**	**74**	**(48)**	**26**
Interest rate contracts	**37**	**—**	**—**	**—**	**37**	**(5)**	**32**
Commodity contracts	**—**	**—**	**—**	**112**	**112**	**(74)**	**38**
	37	**2**	**—**	**184**	**223**	**(127)**	**96**
Deferred amounts and other assets							
Foreign exchange contracts	**13**	**—**	**—**	**39**	**52**	**(34)**	**18**
Interest rate contracts	**19**	**—**	**—**	**—**	**19**	**—**	**19**
Commodity contracts	**16**	**—**	**—**	**15**	**31**	**(29)**	**2**
Other contracts	**1**	**—**	**—**	**—**	**1**	**(1)**	**—**
	49	**—**	**—**	**54**	**103**	**(64)**	**39**
Accounts payable and other							
Foreign exchange contracts	**(5)**	**(25)**	**—**	**(396)**	**(426)**	**48**	**(378)**
Interest rate contracts	**(87)**	**—**	**(4)**	**(185)**	**(276)**	**5**	**(271)**
Commodity contracts	**(1)**	**—**	**—**	**(289)**	**(290)**	**74**	**(216)**
Other contracts	**(1)**	**—**	**—**	**(3)**	**(4)**	**—**	**(4)**
	(94)	**(25)**	**(4)**	**(873)**	**(996)**	**127**	**(869)**
Other long-term liabilities							
Foreign exchange contracts	**—**	**(12)**	**—**	**(1,746)**	**(1,758)**	**34**	**(1,724)**
Interest rate contracts	**(10)**	**—**	**(9)**	**—**	**(19)**	**—**	**(19)**
Commodity contracts	**—**	**—**	**—**	**(158)**	**(158)**	**29**	**(129)**
Other contracts	**(1)**	**—**	**—**	**(1)**	**(2)**	**1**	**(1)**
	(11)	**(12)**	**(9)**	**(1,905)**	**(1,937)**	**64**	**(1,873)**
Total net derivative asset/(liability)							
Foreign exchange contracts	**8**	**(35)**	**—**	**(2,031)**	**(2,058)**	**—**	**(2,058)**
Interest rate contracts	**(41)**	**—**	**(13)**	**(185)**	**(239)**	**—**	**(239)**
Commodity contracts	**15**	**—**	**—**	**(320)**	**(305)**	**—**	**(305)**
Other contracts	**(1)**	**—**	**—**	**(4)**	**(5)**	**—**	**(5)**
	(19)	**(35)**	**(13)**	**(2,540)**	**(2,607)**	**—**	**(2,607)**

December 31, 2017	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Derivative Instruments Used as Fair Value 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	1	4	—	138	143	(83)	60
Interest rate contracts	6	—	2	—	8	(3)	5
Commodity contracts	2	—	—	143	145	(64)	81
	9	4	2	281	296	(150)	146
Deferred amounts and other assets							
Foreign exchange contracts	1	1	—	143	145	(125)	20
Interest rate contracts	7	—	6	—	13	(2)	11
Commodity contracts	17	—	—	6	23	(19)	4
	25	1	6	149	181	(146)	35
Accounts payable and other							
Foreign exchange contracts	(5)	(42)	—	(312)	(359)	83	(276)
Interest rate contracts	(140)	—	(6)	(183)	(329)	3	(326)
Commodity contracts	—	—	—	(439)	(439)	64	(375)
Other contracts	(1)	—	—	(2)	(3)	—	(3)
	(146)	(42)	(6)	(936)	(1,130)	150	(980)
Other long-term liabilities							
Foreign exchange contracts	(4)	(9)	—	(1,299)	(1,312)	125	(1,187)
Interest rate contracts	(38)	—	(2)	—	(40)	2	(38)
Commodity contracts	—	—	—	(186)	(186)	19	(167)
Other contracts	(1)	—	—	—	(1)	-	(1)
	(43)	(9)	(2)	(1,485)	(1,539)	146	(1,393)
Total net derivative asset/(liability)							
Foreign exchange contracts	(7)	(46)	—	(1,330)	(1,383)	—	(1,383)
Interest rate contracts	(165)	—	—	(183)	(348)	—	(348)
Commodity contracts	19	—	—	(476)	(457)	—	(457)
Other contracts	(2)	—	—	(2)	(4)	—	(4)
	(155)	(46)	—	(1,991)	(2,192)	—	(2,192)

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

June 30, 2018	2018	2019	2020	2021	2022	Thereafter[1]
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**572**	**3**	**1**	**—**	**—**	**—**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**2,610**	**3,249**	**3,258**	**1,689**	**1,676**	**3,489**
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**—**	**89**	**25**	**27**	**28**	**149**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)*	**147**	**375**	**—**	**—**	**—**	**—**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**—**	**—**	**35**	**169**	**169**	**889**
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**32,662**	**—**	**—**	**20,000**	**—**
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**2,530**	**2,766**	**547**	**111**	**94**	**204**
Interest rate contracts - long-term receive fixed rate *(millions of Canadian dollars)*	**434**	**592**	**565**	**191**	**104**	**—**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**1,907**	**400**	**454**	**—**	**—**	**—**
Equity contracts *(millions of Canadian dollars)*	**40**	**35**	**20**	**—**	**—**	**—**
Commodity contracts - natural gas *(billions of cubic feet)*	**(2)**	**(35)**	**(22)**	**(9)**	**17**	**2**
Commodity contracts - crude oil *(millions of barrels)*	**6**	**1**	**—**	**—**	**—**	**—**
Commodity contracts - NGL *(millions of barrels)*	**(10)**	**(1)**	**—**	**—**	**—**	**—**
Commodity contracts - power *(megawatt per hour) (MW/H))*	**63**	**64**	**66**	**(3)**	**(43)**	**(43)**

1 As at June 30, 2018, thereafter includes an average net purchase/(sell) of power of (43) MW/H for 2023 through 2025.

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 our consolidated earnings and consolidated comprehensive income, before the effect of income taxes:

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(3)**	3	**18**	1
Interest rate contracts	**17**	(41)	**117**	(55)
Commodity contracts	**(1)**	(9)	**(3)**	12
Other contracts	**12**	(6)	**(2)**	(15)
Net investment hedges				
Foreign exchange contracts	**(5)**	65	**11**	73
	20	12	**141**	16
Amount of (gain)/loss reclassified from AOCI to earnings *(effective portion)*				
Foreign exchange contracts[1]	**(2)**	(102)	**(3)**	(101)
Interest rate contracts[2]	**43**	36	**84**	84
Commodity contracts[3]	**—**	(2)	**(1)**	(4)
Other contracts[4]	**(6)**	4	**3**	13
	35	(64)	**83**	(8)
Amount of (gain)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**11**	4	**10**	6
	11	4	**10**	6

1 Reported within Transportation and other services revenues and Other income/(expense) in the Consolidated Statements of Earnings.

2 Reported within Interest expense in the Consolidated Statements of Earnings.

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

4 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a loss of $11 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 we are hedging exposures to the variability of cash flows is 30 months as at June 30, 2018.

Fair Value Derivatives

For interest rate derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Interest expense in the Consolidated Statements of Earnings. During the three and six months ended June 30, 2018 and 2017, we recognized an unrealized loss of $4 million and $12 million, and an unrealized gain of $3 million and $1 million, respectively, on the derivative and an unrealized gain of $3 million and $11 million, and an unrealized loss of $3 million and $1 million, respectively, on the hedged item in earnings. During the three and six months ended June 30, 2018 and 2017, we recognized a realized gain of $2 million, a realized loss of $1 million, and nil, respectively, on the derivative and a realized loss of $2 million, a realized gain of $1 million, and nil, respectively, on the hedged item in earnings. The difference in the amounts, if any, represents hedge ineffectiveness.

Non-Qualifying Derivatives

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

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**(277)**	434	**(701)**	707
Interest rate contracts[2]	**—**	32	**(2)**	14
Commodity contracts[3]	**(19)**	19	**156**	182
Other contracts[4]	**7**	(5)	**(2)**	(5)
Total unrealized derivative fair value gain/(loss), net	**(289)**	480	**(549)**	898

1 *For the respective six months ended periods, reported within Transportation and other services revenues (2018 - $555 million loss; 2017 - $398 million gain) and Other income/(expense) (2018 - $146 million loss; 2017 - $309 million gain) in the Consolidated Statements of Earnings.*

2 *Reported as an (increase)/decrease within Interest expense in the Consolidated Statements of Earnings.*

3 *For the respective six months ended periods, reported within Transportation and other services revenues (2018 - $3 million gain; 2017 - $37 million loss), Commodity sales (2018 - $10 million gain; 2017 - $197 million gain), Commodity costs (2018 - $127 million gain; 2017 - $9 million gain) and Operating and administrative expense (2018 - $16 million gain; 2017 - $13 million gain) 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 we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our 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. We also maintain current shelf prospectuses with securities regulators which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at June 30, 2018. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

CREDIT RISK

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We have credit concentrations and credit exposure, with respect to derivative instruments, in the following counterparty segments:

	June 30, 2018	December 31, 2017
(millions of Canadian dollars)		
Canadian financial institutions	**29**	82
United States financial institutions	**27**	19
European financial institutions	**97**	145
Asian financial institutions	**20**	2
Other[1]	**98**	137
	271	385

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

As at June 30, 2018, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. We held no cash collateral on derivative asset exposures as at June 30, 2018 and December 31, 2017.

Gross derivative balances have been presented without the effects of collateral posted. Derivative assets are adjusted for non-performance risk of our counterparties using their credit default swap spread rates, and are reflected at fair value. For derivative liabilities, our 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 EGD and Union Gas, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we classify and provide 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

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our 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. Our 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.

We have also categorized the fair value of our held to maturity preferred share investment and long-term debt as Level 2. The fair value of our held to maturity preferred share investment is primarily based on the yield of certain Government of Canada bonds. The fair value of our 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. We have 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. We do not have any other financial instruments categorized in Level 3.

We use the most observable inputs available to estimate the fair value of our derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use 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, we use observable market prices (interest, foreign exchange, commodity and share price) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread as well as the credit default swap spreads associated with our counterparties in our estimation of fair value.

We have categorized our derivative assets and liabilities measured at fair value as follows:

June 30, 2018	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**74**	**—**	**74**
Interest rate contracts	**—**	**37**	**—**	**37**
Commodity contracts	**1**	**8**	**103**	**112**
	1	**119**	**103**	**223**
Long-term derivative assets				
Foreign exchange contracts	**—**	**52**	**—**	**52**
Interest rate contracts	**—**	**19**	**—**	**19**
Commodity contracts	**—**	**4**	**27**	**31**
Other contracts	**—**	**1**	**—**	**1**
	—	**76**	**27**	**103**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(426)**	**—**	**(426)**
Interest rate contracts	**—**	**(276)**	**—**	**(276)**
Commodity contracts	**(20)**	**(51)**	**(219)**	**(290)**
Other contracts	**—**	**(4)**	**—**	**(4)**
	(20)	**(757)**	**(219)**	**(996)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,758)**	**—**	**(1,758)**
Interest rate contracts	**—**	**(19)**	**—**	**(19)**
Commodity contracts	**—**	**(13)**	**(145)**	**(158)**
Other contracts	**—**	**(2)**	**—**	**(2)**
	—	**(1,792)**	**(145)**	**(1,937)**
Total net financial liabilities				
Foreign exchange contracts	**—**	**(2,058)**	**—**	**(2,058)**
Interest rate contracts	**—**	**(239)**	**—**	**(239)**
Commodity contracts	**(19)**	**(52)**	**(234)**	**(305)**
Other contracts	**—**	**(5)**	**—**	**(5)**
	(19)	**(2,354)**	**(234)**	**(2,607)**

December 31, 2017	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	143	—	143
Interest rate contracts	—	8	—	8
Commodity contracts	1	30	114	145
	1	181	114	296
Long-term derivative assets				
Foreign exchange contracts	—	145	—	145
Interest rate contracts	—	13	—	13
Commodity contracts	—	2	21	23
	—	160	21	181
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(359)	—	(359)
Interest rate contracts	—	(329)	—	(329)
Commodity contracts	(13)	(87)	(339)	(439)
Other contracts	—	(3)	—	(3)
	(13)	(778)	(339)	(1,130)
Long-term derivative liabilities				
Foreign exchange contracts	—	(1,312)	—	(1,312)
Interest rate contracts	—	(40)	—	(40)
Commodity contracts	—	(3)	(183)	(186)
Other contracts	—	(1)	—	(1)
	—	(1,356)	(183)	(1,539)
Total net financial liabilities				
Foreign exchange contracts	—	(1,383)	—	(1,383)
Interest rate contracts	—	(348)	—	(348)
Commodity contracts	(12)	(58)	(387)	(457)
Other contracts	—	(4)	—	(4)
	(12)	(1,793)	(387)	(2,192)

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

June 30, 2018	Fair Value	Unobservable Input	Minimum Price/Volatility	Maximum Price/Volatility	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(1)**	**Forward gas price**	**2.52**	**4.57**	**3.38**	**$/mmbtu[2]**
Crude	**(7)**	**Forward crude price**	**55.58**	**74.88**	**66.45**	**$/barrel**
NGL	**(1)**	**Forward NGL price**	**1.24**	**1.36**	**1.33**	**$/gallon**
Power	**(90)**	**Forward power price**	**38.40**	**84.19**	**53.59**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(81)**	**Forward gas price**	**0.78**	**4.91**	**2.05**	**$/mmbtu[2]**
Crude	**(53)**	**Forward crude price**	**38.10**	**110.67**	**86.09**	**$/barrel**
NGL	**(1)**	**Forward NGL price**	**0.45**	**2.36**	**1.04**	**$/gallon**
	(234)					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 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 our 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 our Level 3 derivatives. Changes in price volatility would change the value of the option contracts. Generally, 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:

	Six months ended June 30,	
	2018	2017
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(387)**	(295)
Total gain/(loss)		
Included in earnings[1]	**(7)**	101
Included in OCI	**(2)**	8
Settlements	**162**	82
Level 3 net derivative liability at end of period	**(234)**	(104)

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

Our policy is to recognize transfers as at the last day of the reporting period. There were no transfers between levels as at June 30, 2018 or 2017.

FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

Our other long-term investments in other entities with no actively quoted prices are classified as Fair Value Measurement Alternative (FVMA) investments and are recorded at cost less impairment. The carrying value of FVMA other long-term investments totaled $101 million and $99 million as at June 30, 2018 and December 31, 2017, respectively.

We have Restricted long-term investments held in trust totaling $286 million and $267 million as at June 30, 2018 and December 31, 2017, respectively, which are recognized at fair value.

We have a held to maturity preferred share investment carried at its amortized cost of $381 million and $371 million as at June 30, 2018 and December 31, 2017, respectively. These preferred shares are entitled to a cumulative preferred dividend based on the yield of 10-year Government of Canada bonds plus a margin of 4.50%. As at June 30, 2018 and December 31, 2017, the fair value of this preferred share investment approximates its face value of $580 million.

As at June 30, 2018 and December 31, 2017, our long-term debt had a carrying value of $65.0 billion and $64.0 billion, respectively, before debt issuance costs and a fair value of $66.7 billion and $67.4 billion, respectively. We also have noncurrent notes receivable carried at book value recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at June 30, 2018 and December 31, 2017, the noncurrent notes receivable has a carrying value of $93 million and $89 million, respectively, and a fair value of $93 million and $89 million, respectively.

The fair value of other financial assets and liabilities other than derivative instruments, other long-term investments, Restricted long-term investments and long-term debt approximate their cost due to the short period to maturity.

NET INVESTMENT HEDGES

We have designated a portion of our United States dollar denominated debt, as well as a portfolio of foreign exchange forward contracts, as a hedge of our net investment in United States dollar denominated investments and subsidiaries.

During the six months ended June 30, 2018 and 2017, we recognized an unrealized foreign exchange loss of $301 million a gain of $275 million, respectively, on the translation of United States dollar denominated debt and an unrealized gain on the change in fair value of our outstanding foreign exchange forward contracts of $10 million and $75 million, respectively, in OCI. During the six months ended June 30, 2018 and 2017, we recognized a realized loss of $23 million and $38 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and recognized a realized loss of $14 million and $90 million, respectively, in OCI associated with the settlement of United States dollar denominated debt that had matured during the period. There was no ineffectiveness during the six months ended June 30, 2018 and 2017.

12. INCOME TAXES

The effective income tax rates for the three months ended June 30, 2018 and 2017 were a recovery of 7.9% and an expense of 19.1%, respectively, and for the six months ended June 30, 2018 and 2017 were a recovery of 10.2% and an expense of 18.3%, respectively. The period-over-period decrease in the effective income tax rate is due to the effects of rate-regulated accounting for income taxes and other permanent items relative to the decrease in earnings for the three and six months ended June 30, 2018, the impact of the United States federal corporate income tax rate reduction enacted in 2017, and a recovery related to a change in assertion for the investment in Canadian renewable energy generation assets due to the pending sale which resulted in a revaluation of the related deferred tax liability to the capital gains tax rate and recognition of previously unrecognized tax basis. Refer to *Note 6. Dispositions - Renewable Energy Generation Assets* for further discussion of the transaction.

On December 22, 2017, the United States enacted the TCJA and we made reasonable estimates for the measurement and accounting of certain effects of the TCJA in our consolidated financial statements for the year ended December 31, 2017. We recorded a nil provision for the three and six months ended June 30, 2018, based on existing guidance and legislation, for the remaining effects of the TCJA including the Global Intangible Low Taxed Income tax and the Base Erosion and Anti-abuse Tax.

13. PENSION AND OTHER POSTRETIREMENT BENEFITS

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Service cost	**51**	62	**116**	116
Interest cost	**42**	47	**87**	79
Expected return on plan assets	**(80)**	(73)	**(162)**	(124)
Amortization of actuarial loss	**8**	8	**15**	17
Plan curtailments	**2**	—	**2**	—
Amortization of prior service costs	**—**	—	**(1)**	—
Net periodic benefit costs	**23**	44	**57**	88

14. CONTINGENCIES

We are involved in 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 our interim consolidated financial position or results of operations.

TAX MATTERS

We maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

15. SUBSEQUENT EVENTS

On July 4, 2018, we entered into agreements with Brookfield Infrastructure Partners L.P. and its institutional partners to sell our Canadian natural gas gathering and processing businesses for a cash purchase price of approximately $4.31 billion, subject to customary closing adjustments and receipt of regulatory approvals.

On August 1, 2018, our indirect subsidiary, Enbridge (U.S.) Inc. closed the previously disclosed sale of MOLP to AL Midcoast Holdings, LLC for cash proceeds of US$1.1 billion, less deposits and customary closing adjustments.

On August 1, 2018, we closed the sale of the Renewable Assets to CPPIB for total cash proceeds of $1.75 billion less customary closing items.

Refer to *Note 6. Dispositions* for further discussion of these transactions.

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in Item 1. *Financial Statements* of this report and in conjunction with the audited consolidated financial statements and accompanying footnotes in our Annual Report on Form 10-K for the year ended December 31, 2017, as filed with the Securities and Exchange Commission on February 16, 2018.

MINNESOTA PUBLIC UTILITIES COMMISSION APPROVAL OF U.S. LINE 3 REPLACEMENT PROGRAM

On June 28, 2018, the Minnesota Public Utilities Commission (MNPUC) approved the issuance of a Certificate of Need (Certificate) and pipeline route (Route Permit) for construction of the United States Line 3 Replacement Program (U.S. L3R Program) in Minnesota. The Route Permit adopted our preferred route, with minor modifications and subject to certain conditions. For further details refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program (EEP).*

SIMPLIFICATION OF CORPORATE STRUCTURE

On May 17, 2018 we announced four separate non-binding all-share proposals to the respective boards of directors of our sponsored vehicles, Spectra Energy Partners, LP (SEP), Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEQ) and Enbridge Income Fund Holdings Inc. (ENF), to acquire, in separate combination transactions, all of the outstanding equity securities of those sponsored vehicles not beneficially owned by us. The proposed exchange ratios reflect a value for all of the publicly held equity securities of the sponsored vehicles of $11.4 billion, or 272 million Enbridge common shares, if all are completed on the terms offered based on the closing price of Enbridge's common shares on the Toronto Stock Exchange on May 16, 2018.

The transactions, as proposed, are not expected to have a material impact on our results of operations or cash flows over the 2018 to 2020 horizon.

ASSET MONETIZATION

Renewable Energy Generation Assets
On May 9, 2018, we entered into agreements with the Canadian Pension Plan Investment Board (CPPIB) to sell a 49% interest in all of our Canadian renewable energy generation assets, 49% of two large United States renewable assets and 49% of our interest in the Hohe See Offshore wind farm and its subsequent expansion, both concurrently under construction in Germany, (collectively, the Renewable Assets). Proceeds from the transaction are approximately $1.75 billion. In addition, CPPIB will fund their pro-rata share of the remaining capital expenditures on the Hohe See Offshore wind project. We will maintain a 51% interest in the Renewable Assets and continue to manage, operate and provide administrative services for these assets.

On August 1, 2018, we closed the sale of the Renewable Assets for total cash proceeds of $1.75 billion less customary closing items. These assets were a part of our Green Power and Transmission segment.

Midcoast Operating, L.P.
On May 9, 2018, our indirect subsidiary, Enbridge (U.S.) Inc. entered into a definitive agreement to sell Midcoast Operating, L.P. and its subsidiaries (collectively, MOLP) to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC) for a cash purchase price of approximately US$1.1 billion, subject to customary closing adjustments.

On August 1, 2018, Enbridge (U.S.) Inc. closed the sale of MOLP for total cash proceeds of approximately US$1.1 billion less deposits and other customary closing items.

Canadian Natural Gas Gathering and Processing Businesses
On July 4, 2018, we entered into agreements with Brookfield Infrastructure Partners L.P. and its institutional partners to sell our Canadian natural gas gathering and processing businesses for a cash purchase price of approximately $4.31 billion Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations. The sale of the provincially regulated facilities is expected to close in 2018 for proceeds of approximately $2.5 billion and the sale of the federally regulated facilities is expected to close in mid-2019 for proceeds of approximately $1.8 billion.

REVISED FERC POLICY ON TREATMENT OF INCOME TAXES

On March 15, 2018, the Federal Energy Regulatory Commission (FERC) revised a long standing policy announcing that it would no longer permit entities organized as Master Limited Partnerships (MLPs) to recover an income tax allowance for interstate pipeline assets with cost-of-service rates. The announcement of the Revised Policy Statement was accompanied by: (i) a Notice of Proposed Rulemaking proposing interstate natural gas pipelines file a one-time report to quantify the impact of the federal income tax rate reduction and the impact of the revised Policy Statement on each pipeline; and (ii) a Notice of Inquiry seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation.

We hold our United States liquids and natural gas pipelines through a number of different ownership structures, including MLPs. SEP and EEP have responded to the FERC announcement regarding tax allowance, both directly and through industry associations, objecting to the change in FERC policy and requesting a re-hearing. On April 27, 2018, the FERC issued a tolling order for the purpose of affording it additional time for consideration of matters raised on rehearing. These FERC announcements have adversely affected MLPs generally.

On July 18, 2018, the FERC issued an Order that: (1) dismissed all requests for rehearing of its March 15, 2018 revised policy statement and explained that its revised policy statement does not establish a binding rule, but is instead an expression of general policy that the Commission intends to follow in the future; and (2) provides guidance that if an MLP or other tax pass-through pipeline eliminates its income tax allowance from its cost of service pursuant to FERC’s Revised Policy Statement, then Accumulated Deferred Income Taxes (ADIT) will similarly be removed from its cost of service and MLP pipelines may also eliminate previously-accumulated sums in ADIT instead of flowing ADIT balances back to ratepayers. As a statement of general policy, the FERC will consider alternative application of its tax allowance and ADIT policy on a case-by-case basis.

There are many uncertainties with regards to the implementation of the recent FERC actions, including the potential for different outcomes as the result of a rate case or customer challenges. While there will be varying impacts to each of our sponsored vehicles, on a consolidated basis we do not expect a material impact to our results of operations or cash flows over the 2018 to 2020 horizon. Under the International Joint Tariff (IJT) mechanism on the mainline system, anticipated reductions in the EEP tariff arising from the FERC order would create an offsetting revenue increase on the Canadian mainline system owned by the Fund Group (comprising Enbridge Income Fund, Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and the subsidiaries of EIPLP). At SEP, if implemented as announced, and ultimately supported through a rate case, the ability to eliminate ADIT from cost of service would likely offset the elimination of an income tax allowance in cost of service rates.

UNITED STATES TAX REFORM UPDATE

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (TCJA or United States Tax Reform). As disclosed in our Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 16, 2018, we made certain estimates for the measurement and accounting of certain effects of the TCJA for the year ended and as at December 31, 2017. As we continue to gather, prepare and analyze the necessary information in reasonable detail to complete the accounting for the impact of the TCJA, we continue to refine our estimates. During the first quarter of 2018 we refined our calculation of the regulatory liability associated with the TCJA. This resulted in a reduction of the US$860 million overall regulatory liability at SEP by US$25 million.

We also recorded a nil provision for the three and six months ended June 30, 2018, based on existing guidance and legislation, for the Global Intangible Low Taxed Income tax and the Base Erosion and Anti-abuse Tax.

SEP INCENTIVE DISTRIBUTION RIGHTS

On January 22, 2018, Enbridge and SEP announced the execution of a definitive agreement, resulting in us converting all of our incentive distribution rights (IDRs) and general partner economic interests in SEP into 172.5 million newly issued SEP common units. As part of the transaction, all of the IDRs have been eliminated. We now hold a non-economic general partner interest in SEP and own approximately 403 million SEP common units, representing approximately 83% of SEP's outstanding common units.

RESULTS OF OPERATIONS

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars, except per share amounts)				
Segment earnings/(loss) before interest, income taxes and depreciation and amortization				
Liquids Pipelines	**1,322**	1,657	**2,478**	3,137
Gas Transmission and Midstream	**1,014**	932	**1,140**	1,407
Gas Distribution	**370**	310	**1,006**	697
Green Power and Transmission	**126**	101	**235**	202
Energy Services	**35**	(17)	**204**	139
Eliminations and Other	**(118)**	(16)	**(397)**	(314)
Depreciation and amortization	**(829)**	(868)	**(1,653)**	(1,540)
Interest expense	**(690)**	(565)	**(1,346)**	(1,051)
Income tax recovery/(expense)	**97**	(293)	**170**	(491)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(167)**	(241)	**(143)**	(465)
Preference share dividends	**(89)**	(81)	**(178)**	(164)
Earnings attributable to common shareholders	**1,071**	919	**1,516**	1,557
Earnings per common share	**0.63**	0.56	**0.90**	1.11
Diluted earnings per common share	**0.63**	0.56	**0.90**	1.10

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Three months ended June 30, 2018, compared with the three months ended June 30, 2017

Earnings Attributable to Common Shareholders for both the three months ended June 30, 2018 and the three months ended June 30, 2017 were positively impacted by a complete quarter of contributions from new assets following the completion of the stock-for-stock merger between Enbridge and Spectra Energy Corp on February 27, 2017 (Merger Transaction).

Earnings Attributable to Common Shareholders was negatively impacted by $280 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized derivative fair value loss of $298 million ($163 million after-tax attributable to us) in 2018, compared with a gain of $461 million ($292 million after-tax attributable to us) in the corresponding 2017 period, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks;
- the absence in the second quarter of 2018 of a $67 million gain ($8 million after-tax attributable to us) recorded in the second quarter of 2017 on the sale of pipe offset by project wind-down costs related to EEP's Sandpiper Project;
- asset monetization transaction costs of $20 million ($15 million after-tax attributable to us) recorded in 2018; partially offset by
- a deferred income tax recovery of $258 million ($190 million after-tax attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation assets due to the pending sale, which resulted in a revaluation of the related deferred tax liability to the capital gains tax rate and recognition of previously unrecognized tax basis;

- employee severance, transition and transformation costs of $29 million ($27 million after-tax attributable to us) in 2018, compared with $79 million ($50 million after-tax attributable to us) in the corresponding 2017 period;
- the absence in the second quarter of 2018 of transaction costs of $26 million ($19 million after-tax attributable to us) recorded in the second quarter of 2017 related to the Merger Transaction; and
- project development costs of $4 million ($1 million after-tax attributable to us) compared with $24 million ($18 million after-tax attributable to us) in the corresponding 2017 period.

As it pertains to the non-cash, unrealized derivative fair value gains and losses discussed above, we have a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on financial derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining $432 million increase is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to a higher realized foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues, a higher IJT Benchmark Toll and higher throughput driven by capacity optimization initiatives implemented in 2017;
- contributions from new Liquids Pipelines assets placed into service in 2017;
- contributions from new Gas Transmission and Midstream assets placed into service in 2017 and the first quarter of 2018;
- increased earnings from our Gas Transmission and Midstream equity investments due to favorable margins, favorable commodity prices and increased volume commitments;
- increased earnings from our Gas Distribution segment due to colder weather, expansion projects and higher distribution charges resulting from growth in rate base; partially offset by
- higher interest expense primarily due to long-term debt issuances in 2017 and the first half of 2018 to finance capital expansions.

The growth in earnings per common share relative to the second quarter of 2017 is primarily due to the increase in Earnings Attributable to Common Shareholders, partially offset by the increase in common shares from the issuance of approximately 33 million common shares in December 2017 through a private placement offering and ongoing quarterly issuances under our Dividend Reinvestment and Share Purchase Plan (DRIP).

Six months ended June 30, 2018, compared with the six months ended June 30, 2017

Earnings Attributable to Common Shareholders for the six month period ended June 30, 2018 were positively impacted by contributions in the first two months of 2018 of approximately $364 million from new assets that were absent in 2017 due to the timing of the completion of the Merger Transaction.

After taking into consideration the contribution of additional earnings from the Merger Transaction, Earnings Attributable to Common Shareholders was negatively impacted by $1,173 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a loss in 2018 of $913 million ($701 million after-tax attributable to us) on MOLP resulting from a revision to the fair value of the assets held for sale based on the sale price; refer to Part I. Item 1. *Financial Statements - Note 6. Dispositions*;
- a non-cash, unrealized derivative fair value loss of $575 million ($309 million after-tax attributable to us) in 2018, compared with a gain of $877 million ($537 million after-tax attributable to us) in the corresponding 2017 period, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks;

- a loss of $154 million ($95 million after-tax attributable to us) in 2018 related to the Line 10 crude oil pipeline (Line 10), which is a component of our mainline system, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell;
- the absence in the first half of 2018 of a $62 million gain ($7 million after-tax attributable to us) recorded in the first half of 2017 on the sale of pipe offset by project wind-down costs related to EEP's Sandpiper Project;
- asset monetization transaction costs of $20 million ($15 million after-tax attributable to us) recorded in 2018; partially offset by
- a deferred income tax recovery of $258 million ($190 million after-tax attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation assets due to the pending sale which resulted in a revaluation of the related deferred tax liability to the capital gains tax rate and recognition of previously unrecognized tax basis;
- employee severance, transition and transformation costs of $126 million ($123 million after-tax attributable to us) in 2018, compared with $208 million ($128 million after-tax attributable to us) in the corresponding 2017 period;
- the absence in the first half of 2018 of transaction costs of $178 million ($130 million after-tax attributable to us) recorded in the first half of 2017 related to the Merger Transaction;
- project development costs of $7 million ($3 million after-tax attributable to us) compared with $25 million ($19 million after-tax attributable to us) in the corresponding 2017 period;
- a gain of $116 million after-tax attributable to us in 2018, compared with a loss of $5 million in the corresponding 2017 period, resulting from the reallocation of income between our interest and the noncontrolling interests in Enbridge Energy Partners, L.P. (EEP) to resolve capital account deficits as required under EEP’s partnership agreement; and
- a gain of $63 million after-tax attributable to us in 2018 resulting from the impact of United States Tax Reform on our United States Green Power and Transmission assets.

After taking into consideration the factors above, the remaining $768 million increase is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to a higher foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues, a higher IJT Benchmark Toll and higher throughput driven by capacity optimization initiatives implemented in 2017;
- contributions from new Liquids Pipelines assets placed into service in 2017;
- contributions from new Gas Transmission and Midstream assets placed into service in 2017 and the first quarter of 2018;
- increased earnings from our Gas Transmission and Midstream equity investments due to favorable margins, favorable commodity prices and increased volume commitments;
- increased earnings from our Gas Distribution segment due to colder weather, expansion projects and higher distribution charges resulting from growth in rate base; partially offset by
- higher interest expense primarily due to long-term debt issuances in 2017 and the first half of 2018 to finance capital expansions.

Lower earnings per common share is primarily due to the decrease in Earnings Attributable to Common Shareholders, the increase in common shares from the issuance of approximately 33 million common shares in December 2017 in a private placement offering, the issuance of approximately 691 million common shares in February 2017 as part of the consideration for the Merger Transaction and ongoing quarterly issuances under our DRIP.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**1,322**	1,657	**2,478**	3,137

Three months ended June 30, 2018, compared with the three months ended June 30, 2017

EBITDA decreased by $640 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized loss of $275 million in 2018 compared with a $274 million gain in 2017 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks; and
- the absence in the first quarter of 2018 of a $67 million gain recorded in the first quarter of 2017 on the sale of pipe offset by project wind-down costs related to EEP's Sandpiper Project.

After taking into consideration the factors above, the remaining $305 million increase is primarily explained by the following significant business factors:

- a higher foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues of $1.26 in 2018 compared with $1.04 in 2017;
- a higher IJT Benchmark Toll of $4.07 in 2018 compared with $4.05 in 2017, and higher toll surcharges for the recovery of costs related to certain expansion projects;
- higher Canadian Mainline ex-Gretna throughput of 2,636 thousands of barrels per day (kbpd) in 2018 compared with 2,449 kbpd in 2017 driven by capacity optimization initiatives implemented in 2017;
- higher Lakehead System throughput of 2,777 kbpd in 2018 compared with 2,604 kbpd in 2017 driven by capacity optimization initiatives implemented in 2017;
- contributions from assets placed into service during 2017, including the Wood Buffalo Extension Pipeline and the Norlite Pipeline System and the acquisition of a minority interest in the Bakken Pipeline System; partially offset by
- the net unfavorable effect of translating United States dollar EBITDA at a lower Canadian to United States dollar average exchange rate (Average Exchange Rate) of $1.29 in 2018 compared with $1.34 in 2017.

Six months ended June 30, 2018, compared with the six months ended June 30, 2017

EBITDA for the six month period ended June 30, 2018 was positively impacted by contributions in the first two months of 2018 of approximately $53 million from new assets that were absent in 2017 due to the timing of the completion of the Merger Transaction.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA decreased by $1,266 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized loss of $573 million in 2018 compared with a $439 million gain in 2017 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks;
- a loss of $154 million in 2018 related to Line 10, which is a component of our mainline system, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell; and

- the absence in the first half of 2018 of a $62 million gain recorded in the first half of 2017 on the sale of pipe offset by project wind-down costs related to EEP's Sandpiper Project.

After taking into consideration the factors above, the remaining $554 million increase is primarily explained by the following significant business factors:

- a higher foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues of $1.26 in 2018 compared with $1.04 in 2017;
- a higher IJT Benchmark Toll of $4.07 in 2018 compared with $4.05 in 2017, and higher toll surcharges for the recovery of costs related to certain expansion projects;
- higher Canadian Mainline ex-Gretna throughput of 2,631 kbpd in 2018 compared with 2,521 kbpd in 2017 driven by capacity optimization initiatives implemented in 2017;
- higher Lakehead System throughput of 2,771 kbpd in 2018 compared with 2,675 kbpd in 2017 driven by capacity optimization initiatives implemented in 2017;
- contributions from assets placed into service during 2017, including the Wood Buffalo Extension Pipeline and the Norlite Pipeline System and the acquisition of a minority interest in the Bakken Pipeline System;
- increased transportation revenues resulting from an increase in the level of committed take-or-pay volumes and higher spot volumes on Flanagan South Pipeline driven by strong demand in the United States Gulf Coast; partially offset by
- the net unfavorable effect of translating United States dollar EBITDA at a lower Average Exchange Rate of $1.28 in 2018 compared with $1.33 in 2017.

GAS TRANSMISSION AND MIDSTREAM

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**1,014**	932	**1,140**	1,407

Three months ended June 30, 2018, compared with the three months ended June 30, 2017

EBITDA decreased by $33 million due to certain unusual, infrequent or other market factors primarily explained by the following:

- a non-cash, unrealized loss of $4 million in 2018 compared with a gain of $17 million in 2017 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risk.

After taking into consideration the factors above, the remaining $115 million increase is primarily explained by the following significant business factors:

- contributions from assets placed into service in 2017 and the first quarter of 2018, including the Sabal Trail Transmission, LLC (Sabal Trail), Access South, Adair Southwest and Lebanon Extension, High Pine and Wyndwood pipelines;
- increased fractionation margins at our Aux Sable joint venture driven by higher NGL prices and increased demand;
- favorable seasonal firm and interruptible revenues from our Alliance joint venture that resulted from wider basis differentials;
- increased margins on our United States Midstream assets resulting from favorable commodity prices;
- lower operating costs achieved on our Canadian assets; partially offset by
- the net unfavorable effect of translating United States dollar EBITDA at a lower Average Exchange Rate of $1.29 in 2018 compared with $1.34 in 2017.

Six months ended June 30, 2018, compared with the six months ended June 30, 2017

EBITDA for the six month period ended June 30, 2018 was positively impacted by contributions in the first two months of 2018 of approximately $570 million from new assets that were absent in 2017 due to the timing of the completion of the Merger Transaction. When compared to pre-merger results from the prior period, operating results from the new assets include higher earnings primarily from business expansion projects on Algonquin Gas Transmission, Sabal Trail and Texas Eastern Transmission, LP.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA decreased by $956 million due to certain unusual, infrequent or other market factors primarily explained by the following:

- a loss of $913 million on MOLP resulting from a revision to the fair value of the assets held for sale based on the sale price; refer to Part I. Item 1. *Financial Statements - Note 6. Dispositions*; and
- a non-cash, unrealized gain of $2 million in 2018 compared with a gain of $27 million recorded in 2017 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risk.

After taking into consideration the factors above, the remaining $119 million increase is primarily explained by the following significant business factors:

- contributions from assets placed into service in 2017 and the first quarter of 2018, including the Sabal Trail, Access South, Adair Southwest and Lebanon Extension, High Pine and Wyndwood pipelines;
- increased fractionation margins at our Aux Sable joint venture driven by higher NGL prices and increased demand;
- favorable seasonal firm and interruptible revenues from our Alliance joint venture that resulted from wider basis differentials;
- lower operating costs achieved on our United States Midstream and Canadian assets; partially offset by
- the net unfavorable effect of translating United States dollar EBITDA at a lower Average Exchange Rate of $1.28 in 2018 compared with $1.33 in 2017.

GAS DISTRIBUTION

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**370**	310	**1,006**	697

Three months ended June 30, 2018, compared with the three months ended June 30, 2017

EBITDA increased by $60 million primarily due to the following significant business factors:

- increased earnings of $20 million period-over-period resulting from colder weather experienced in our franchise service areas; and
- higher earnings from expansion projects, and higher distribution charges primarily resulting from increase in rate base and customer base.

Six months ended June 30, 2018, compared with the six months ended June 30, 2017

EBITDA for the six month period ended June 30, 2018 was positively impacted by contributions in the first two months of 2018 of approximately $180 million from Union Gas Limited (Union Gas) that were absent in 2017 due to the timing of the completion of the Merger Transaction. When compared to pre-merger results from the prior period, Union Gas' operating results benefited from colder weather and higher revenues primarily due to expansion.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA decreased by $15 million due to certain unusual, infrequent and other business factors, primarily explained by the following:

- a non-cash, unrealized gain of $3 million in 2018 compared with a gain of $10 million in 2017 arising from the change in the mark-to-market value of Noverco Inc.'s derivative financial instruments; and
- a negative equity earnings adjustment of $9 million at Noverco Inc. in 2018 arising from United States Tax Reform.

After taking into consideration the factors above, the remaining $144 million increase is primarily explained by the following significant business factors:

- increased earnings of $45 million period-over-period resulting from colder weather experienced in our franchise service areas; and
- higher earnings from expansion projects, and higher distribution charges primarily resulting from increase in rate base and customer base.

GREEN POWER AND TRANSMISSION

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**126**	101	**235**	202

Three months ended June 30, 2018, compared with the three months ended June 30, 2017

EBITDA increased by $25 million primarily due to the following significant business factors:

- lower operating costs at Canadian and United States wind farms; and
- contributions from the Rampion Offshore Wind Project, which generated first power in November 2017 and reached full operating capacity in the second quarter of 2018.

Six months ended June 30, 2018, compared with the six months ended June 30, 2017

EBITDA decreased by $29 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- an asset impairment charge of $22 million in 2018 from our equity investment in NRGreen Power Limited Partnership related to the Chickadee Creek waste heat recovery facility in Alberta; and
- a loss of $11 million in 2018 from our equity investment in Rampion Offshore Wind Limited resulting from damaged cables.

After taking into consideration the factors above, the remaining $62 million increase is primarily explained by the following significant business factors:

- stronger wind resources and lower operating costs at Canadian and United States wind farms;
- contributions from the Chapman Ranch Wind Project, which was placed into service in October 2017;
- contributions from the Rampion Offshore Wind Project, which generated first power in November 2017 and reached full operating capacity in the second quarter of 2018; and
- a net gain of $11 million from an arbitration settlement related to our Canadian wind facilities.

ENERGY SERVICES

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**35**	(17)	**204**	139

EBITDA from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Three months ended June 30, 2018, compared with the three months ended June 30, 2017

EBITDA decreased by $13 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized loss of $27 million in 2018 compared with a loss of $14 million in 2017 reflecting the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining $65 million increase is primarily explained by the following significant business factor:

- increased earnings from Energy Services' Canadian and United States crude operations due to the widening of certain location and quality differentials in 2018, which increased opportunities to generate profitable margins.

Six months ended June 30, 2018, compared with the six months ended June 30, 2017

EBITDA decreased by $26 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized gain of $120 million in 2018 compared with a gain of $146 million in 2017 reflecting the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining $91 million increase is primarily explained by the following significant business factors:

- the impact of colder weather in the first quarter of 2018 on natural gas location differentials which created more opportunities to generate profitable margins from our Energy Services' gas marketing business; and
- increased earnings from Energy Services' Canadian and United States crude operations due to the widening of certain location and quality differentials in 2018, which increased opportunities to generate profitable margins.

ELIMINATIONS AND OTHER

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Loss before interest, income taxes and depreciation and amortization	**(118)**	(16)	**(397)**	(314)

Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements, all of which are not allocated to business segments. Eliminations and Other also includes new business development activities, general corporate investments and a portion of the synergies achieved thus far related to the integration of corporate functions due to the Merger Transaction.

Three months ended June 30, 2018, compared with the three months ended June 30, 2017

Loss before interest, income taxes and depreciation and amortization increased by $118 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of $5 million in 2018 compared with a $184 million gain in 2017 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- asset monetization transaction costs of $20 million recorded in 2018; partially offset by
- employee severance, transition and transformation costs of $26 million in 2018 compared with $79 million in 2017;
- the absence in the first quarter of 2018 of transaction costs compared with $25 million of costs recorded in the first quarter of 2017 related to the Merger Transaction; and
- project development costs of $4 million in 2018 compared with $21 million in 2017.

After taking into consideration the factors above, the remaining $16 million decrease is primarily explained by the following significant business factor:

- a realized loss of $53 million in 2018 compared with a loss of $70 million in 2017 related to settlements under our foreign exchange risk management program.

Six months ended June 30, 2018, compared with the six months ended June 30, 2017

Loss before interest, income taxes and depreciation and amortization increased by $113 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized loss of $131 million in 2018 compared with a $256 million gain in 2017 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- asset monetization transaction costs of $20 million recorded in 2018; partially offset by
- employee severance, transition and transformation costs of $88 million in 2018 compared with $204 million in 2017;
- the absence in the first half of 2018 of transaction costs compared with $174 million of costs recorded in the first half of 2017 related to the Merger Transaction; and
- project development costs of $4 million in 2018 compared with $21 million in 2017.

After taking into consideration the factors above, the remaining $30 million decrease is primarily explained by the following significant business factors:

- a realized loss of $95 million in 2018 compared with a loss of $142 million in 2017 related to settlements under our foreign exchange risk management program; partially offset by
- two additional months of eliminations and other costs post-Merger Transaction, net of corporate synergies.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

The following table summarizes the status of our commercially secured projects, organized by business segment:

		Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status	Expected In-Service Date
(Canadian dollars, unless stated otherwise)						
LIQUIDS PIPELINES						
1.	Canadian Line 3 Replacement Program (the Fund Group)[3]	100%	$5.3 billion	$2.6 billion	Under construction	2H - 2019
2.	U.S. Line 3 Replacement Program (EEP)[4]	100%	US$2.9 billion	US$0.9 billion	Pre-construction[5]	2H - 2019
3.	Other - United States[6]	100%	US$0.4 billion	US$0.4 billion	Substantially complete	2H - 2019
4.	Other - Canada[7]	100%	$0.1 billion	$0.1 billion	Complete	In service
GAS TRANSMISSION AND MIDSTREAM						
5.	Atlantic Bridge (SEP)	100%	US$0.6 billion	US$0.4 billion	Under construction	Q4 - 2018
6.	NEXUS (SEP)	50%	US$1.3 billion	US$0.8 billion	Under construction	Q3 - 2018
7.	Reliability and Maintainability Project	100%	$0.5 billion	$0.5 billion	Under construction	Q3 - 2018
8.	Valley Crossing Pipeline	100%	US$1.6 billion	US$1.5 billion	Under construction	Q4 - 2018
9.	Spruce Ridge Program	100%	$0.5 billion	$0.1 billion	Pre-construction	Q1 - 2020
10.	T-South Expansion Program	100%	$1.0 billion	No significant expenditures to date	Pre-construction	2H - 2020
11.	Other - United States[8]	100%	US$2.1 billion	US$1.0 billion	Various stages	2018 - 2021
12.	Other - Canada[9]	100%	$0.6 billion	$0.6 billion	Complete	In service
GREEN POWER AND TRANSMISSION						
13.	Rampion Offshore Wind Project	24.9%	$0.8 billion (£0.37 billion)	$0.6 billion (£0.3 billion)	Complete	In service
14.	Hohe See Offshore Wind Project and Expansion[10]	25%	$1.1 billion (€0.67 billion)	$0.5 billion (€0.3 billion)	Under construction	2H - 2019

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

2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to June 30, 2018.

3 The Fund Group is comprised of Enbridge Income Fund, Enbridge Commercial Trust, Enbridge Income Partners LP and the subsidiaries and investees of Enbridge Income Partners LP.

4 The U.S. L3R Program is being funded 99% by Enbridge and 1% by EEP.

5 Construction of the Wisconsin portion of the project is complete as noted below. The remaining project is in pre-construction status.

6 Includes the Lakehead System Mainline Expansion - Line 61. Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program.

7 Includes the $0.1 billion Line 45 Cheecham connectivity placed into service in the second quarter of 2018.

8 Includes the US$0.2 billion Stampede Offshore oil lateral placed into service in the first quarter of 2018.

9 Includes the $0.4 billion High Pine and the $0.2 billion Wyndwood pipeline expansion, both placed into service in the first quarter of 2018.

10 We entered into an agreement to sell 49% of our 50% ownership interest. Upon closing of the sale, our ownership interest was reduced to approximately 25%. Refer to Asset Monetization*.*

A full description of each of our projects is provided in our Annual Report on Form 10-K, as filed with the Securities and Exchange Commission on February 16, 2018. Significant updates that have occurred since the date of filing are discussed below.

LIQUIDS PIPELINES

- **United States Line 3 Replacement Program (EEP)** - the Wisconsin portion of the U.S. L3R Program is in service. For additional updates on the project, refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program (EEP)*.

GAS TRANSMISSION AND MIDSTREAM

- **Atlantic Bridge** - expansion of SEP's Algonquin Gas Transmission systems to transport 133 mmcf/d of natural gas to the New England region. Due to ongoing permitting delays in Massachusetts, the revised cost of the project is US$0.6 billion. This is roughly 17% above prior estimates.

- **Valley Crossing Pipeline** - a natural gas pipeline connecting the Agua Dulce hub in Texas to an offshore tie-in with the Sur de Texas-Tuxpan project, which is being constructed by a third party. The project will help Mexico meet its growing gas fired electric generation needs by providing capacity of up to approximately 2.6 billion cubic feet per day. Based on an updated execution plan, the revised cost of the project is US$1.6 billion. This is roughly 12% above prior estimates and reflects scope changes, reroutes and offshore weather delays.

- **Spruce Ridge Program** - natural gas pipeline expansion of Westcoast Energy Inc.'s British Columbia Pipeline in northern British Columbia, which consists of the Aitken Creek Looping project and the Spruce Ridge Expansion project. As a result of regulatory delays, the revised expected in-service date of the program is the first quarter of 2020.

GREEN POWER AND TRANSMISSION

- **Rampion Offshore Wind Project** - the project generated first power in November 2017. All remaining turbines were commissioned in March 2018 and full operating capacity was reached in the second quarter of 2018.

GROWTH PROJECTS - REGULATORY MATTERS

United States Line 3 Replacement Program (EEP)
EEP is in the process of obtaining the appropriate permits for constructing the U.S. L3R Program in Minnesota. The project requires both a Certificate and Route Permit from the MNPUC.

On June 28, 2018, the MNPUC approved the issuance of a Certificate and Route Permit that adopts EEP's preferred route, with minor modifications and subject to certain conditions. A written order documenting the MNPUC's rulings in the Certificate and Route Permit dockets is expected by September 2018. Permits are also required from the United States Army Corps of Engineers (Army Corps), state agencies (including the Minnesota Department of Natural Resources and the Minnesota Pollution Control Agency) and local governments in Minnesota. EEP anticipates the receipt of all required permits in time to mobilize their contractors and commence construction activities during the first quarter of 2019.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by us, but have not yet met our criteria to be classified as commercially secured:

LIQUIDS PIPELINES

- **Gray Oak Pipeline Project** - the Gray Oak Pipeline, LLC announced on April 24, 2018, that it received sufficient binding commitments on an initial open season to proceed with construction of the Gray Oak Pipeline. A second open season was completed in July 2018. The Gray Oak Pipeline will provide crude oil transportation from West Texas to destinations in the Corpus Christi and Sweeny/Freeport markets. The pipeline is expected to be placed in service by the end of 2019 and could have an ultimate capacity of approximately one million barrels per day, subject to additional shipper commitments. We have secured an option to acquire an interest in the pipeline.

GAS TRANSMISSION AND MIDSTREAM

- **Alliance Pipeline Expansion Project** - on March 28, 2018, Alliance Pipeline announced an open season for binding bids for additional long-term firm transportation service contracts on the Alliance Pipeline Canada and Alliance Pipeline US systems in support of up to 400 million cubic feet per day (mmcf/d) of expanded services on Alliance Pipeline Canada and up to 430 mmcf/d of expanded services on Alliance Pipeline US, with an anticipated in-service date in the fourth quarter of 2021. The open season closed on May 30, 2018, and the binding commitments did not reach the targets for additional long-term firm transportation service noted above. Based on these results and feedback from producers, Alliance Pipeline is assessing potential alternatives and next steps.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to our growth strategy, particularly in light of the significant number and size of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside our 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, we actively manage financial plans and strategies to ensure we maintain sufficient liquidity to meet routine operating and future capital requirements. In the near term, we generally expect to utilize cash from operations together with commercial paper issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Our 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.

CAPITAL MARKET ACCESS

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive.

Credit Facilities and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities as at June 30, 2018.

		June 30, 2018		
	Maturity Dates	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.[2]	2019-2022	**6,537**	**1,761**	**4,776**
Enbridge (U.S.) Inc.	2019	**1,861**	**456**	**1,405**
Enbridge Energy Partners, L.P.[3]	2019-2022	**3,453**	**2,261**	**1,192**
Enbridge Gas Distribution Inc.	2019	**1,017**	**794**	**223**
Enbridge Income Fund	2020	**1,500**	**351**	**1,149**
Enbridge Pipelines Inc.	2019	**3,000**	**1,906**	**1,094**
Spectra Energy Partners, LP[4]	2022	**3,289**	**1,528**	**1,761**
Union Gas	2021	**700**	**230**	**470**
Total committed credit facilities		**21,357**	**9,287**	**12,070**

1 Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.
2 Includes $135 million, $164 million (US$125 million) and $150 million of commitments that expire in 2018, 2018 and 2020, respectively.
3 Includes $230 million (US$175 million) and $243 million (US$185 million) of commitments that expire in 2018 and 2020, respectively.
4 Includes $443 million (US$336 million) of commitments that expire in 2021.

During the second quarter of 2018, Enbridge (U.S.) Inc. terminated a US$500 million credit facility, which was set to mature in 2019, and repaid drawn amounts. In addition, an unutilized Enbridge US$100 million credit facility expired.

During the first quarter of 2018, Enbridge terminated a US$650 million credit facility, which was set to mature in 2019, and repaid drawn amounts. In addition, Enbridge (U.S.) Inc. terminated an unutilized US$950 million credit facility, which was set to mature in 2019.

During the first quarter of 2018, Westcoast Energy Inc. terminated an unutilized $400 million credit facility with a syndicate of banks. The facility was acquired in conjunction with the Merger Transaction and was set to mature in 2021.

In addition to the committed credit facilities noted above, we maintain $796 million of uncommitted demand credit facilities, of which $517 million were unutilized as at June 30, 2018. As at December 31, 2017, we had $792 million of uncommitted credit facilities, of which $518 million were unutilized.

Our net available liquidity of $12,527 million as at June 30, 2018, was inclusive of $457 million of unrestricted cash and cash equivalents as reported in the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at June 30, 2018, we were in compliance with all debt covenants and we expect to continue to comply with such covenants.

LONG-TERM DEBT ISSUANCES

During the six months ended June 30, 2018, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.			
	March 2018	Fixed-to-floating rate notes due 2078[1]	US$850
	April 2018	Fixed-to-floating rate notes due 2078[2]	$750
	April 2018	Fixed-to-floating rate notes due 2078[3]	US$600
Spectra Energy Partners, LP[4]			
	January 2018	3.50% senior notes due 2028	US$400
	January 2018	4.15% senior notes due 2048	US$400

1 *Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.25%. Subsequently, the interest rate will be set to equal the three-month London Interbank Offered Rate (LIBOR) plus a margin of 364 basis points from years 10 to 30, and a margin of 439 basis points from years 30 to 60.*

2 *Notes mature in 60 years and are callable on or after year 10. For the initial 10 years, the notes carry a fixed interest rate of 6.625%. Subsequently, the interest rate will be set to equal the Canadian Dollar Offered Rate plus a margin of 432 basis points from years 10 to 30, and a margin of 507 basis points from years 30 to 60.*

3 *Notes mature in 60 years and are callable on or after year five. For the initial five years, the notes carry a fixed interest rate of 6.375%. Subsequently, the interest rate will be set to equal the three-month LIBOR plus a margin of 359 basis points from years five to 10, a margin of 384 basis points from years 10 to 25, and a margin of 459 basis points from years 25 to 60.*

4 *Issued through Texas Eastern Transmission, LP, a wholly-owned operating subsidiary of SEP.*

LONG-TERM DEBT REPAYMENTS

During the six months ended June 30, 2018, we completed the following long-term debt repayments to further simplify our debt financing structure post-merger:

Company	Retirement/Repayment Date		Principal Amount	Cash Consideration[1]
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Energy Partners, L.P.				
	April 2018	6.50% senior notes	US$400	
Enbridge Pipelines (Southern Lights) L.L.C				
	June 2018	3.98% medium-term notes due June 2040	US$20	
Enbridge Southern Lights LP				
	January 2018	4.01% medium-term notes due June 2040	$9	
Spectra Energy Capital, LLC				
Repurchase via Tender Offer[2]				
	March 2018	6.75% senior unsecured notes due 2032	US$64	US$80
	March 2018	7.50% senior unsecured notes due 2038	US$43	US$59
Redemption[2]				
	March 2018	5.65% senior unsecured notes due 2020	US$163	US$172
	March 2018	3.30% senior unsecured notes due 2023	US$498	US$508
Repayment				
	April 2018	6.20% senior notes	US$272	
Union Gas				
	April 2018	5.35% medium-term notes	$200	
Westcoast Energy Inc.				
	May 2018	6.90% senior secured notes	$13	
	May 2018	4.34% senior secured notes	$4	

1 Cash consideration disclosed for repayments where the cash paid differs from the principal amount.
2 The loss on debt extinguishment of $37 million (US$29 million), net of the fair value adjustment recorded upon completion of the Merger Transaction, was reported within Interest expense in the Consolidated Statements of Earnings.

On July 9, 2018, Midcoast Energy Partners, L.P. completed a redemption of the principal amount of its outstanding senior notes carrying interest rates ranging from 3.56% to 4.42%, with maturities ranging from 2019 to 2024. The principal amount redeemed was US$400 million for a cash consideration of US$415 million.

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model support our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and help ensure ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at June 30, 2018, our debt capitalization ratio was 47.5%, compared with 48.3% as at December 31, 2017.

There are no material restrictions on our cash. Total restricted cash of $165 million, includes Enbridge Gas Distribution Inc.'s (EGD) and Union Gas' receipt of cash from the Government of Ontario to fund its Green Investment Fund program. In addition, our restricted cash includes cash collateral and amounts received in respect of specific shipper commitments. Cash and cash equivalents held by EEP, the Fund Group and SEP are generally not readily accessible by us until distributions are declared and paid by these entities, which occurs quarterly for EEP and SEP, and monthly for the Fund Group. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by us.

Excluding current maturities of long-term debt, we had a negative working capital position as at June 30, 2018. The major contributing factor to the negative working capital position was the ongoing funding of our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due. As at June 30, 2018 and December 31, 2017, our net available liquidity totaled $12,527 million and $12,959 million, respectively.

SOURCES AND USES OF CASH

	Six months ended June 30,	
	2018	2017
(millions of Canadian dollars)		
Operating activities	**6,538**	3,747
Investing activities	**(3,139)**	(5,829)
Financing activities	**(3,399)**	1,678
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**35**	(32)
Increase/(decrease) in cash and cash equivalents and restricted cash	**35**	(436)

Significant sources and uses of cash for the six months ended June 30, 2018 and June 30, 2017 are summarized below:

Operating Activities

- The growth in cash flow delivered by operations during the six months ended June 30, 2018 is a reflection of the positive operating factors discussed under *Results of Operations*. The increase in operating cash flow was driven mainly by contributions from new assets placed into service in 2017 and 2018 and from new assets following the completion of the Merger Transaction.
- Changes in operating assets and liabilities included within operating activities were $1,600 million and $497 million for the six months ended June 30, 2018 and 2017, respectively. Our operating assets and liabilities fluctuate in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within the Energy Services and Gas Distribution segments, the timing of tax payments, as well as timing of cash receipts and payments generally.

Investing Activities

- The decrease of cash used in investing activities during the first half of 2018 compared with the corresponding period in 2017 was primarily attributable to activity in the first half of 2017 that was not present in the first half of 2018, related primarily to the acquisition of an interest in the Bakken Pipeline System of $2.0 billion (US$1.5 billion), partially offset by cash acquired in the Merger Transaction of $0.7 billion and cash received from asset dispositions of $0.3 billion.
- Further adding to the decrease of cash used in investing activities were distributions from equity investments in excess of cumulative earnings of $1,140 million and $39 million for the six months ended June 30, 2018 and 2017, respectively. On April 30, 2018, SEP received a distribution from Sabal Trail in the amount of $952 million (US$744 million) as a partial return of capital for construction and development costs previously funded by Sabal Trail's partners.
- We are continuing with the execution of our growth capital program which is further described in *Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

Financing Activities

- During the first half of 2018, we used cash in financing activities of $3,399 million compared to cash provided by financing activities of $1,678 million for the corresponding period in 2017. The change was primarily attributable to repayments of maturing term notes and credit facilities. During the six months ended June 30, 2018, we issued hybrid securities, the proceeds of which were used to repay maturing term notes and credit facilities and to finance growth capital programs. Proceeds from the hybrid securities were primarily used to repay credit facilities and to repurchase or redeem Spectra Energy Capital, LLC's outstanding senior unsecured notes as discussed in *Liquidity and Capital Resources - Long-Term Debt Repayments.*
- Cash from financing activities decreased as a result of decreased contributions from noncontrolling interests and redeemable noncontrolling interests of $432 million and $559 million, respectively. Noncontrolling interest contributions received in the first half of 2017 related to completed projects for which there were no contributions received from noncontrolling interests in 2018. In April 2017, contributions from redeemable noncontrolling interests were received from a secondary public offering attributable to our holdings in ENF. There were no similar offerings during the first half of 2018.
- Finally, with the exception of dividends paid to Spectra Energy Corp shareholders that were declared prior to the Merger Transaction, our common share dividend payments increased in the six months ended June 30, 2018, primarily due to the increase in the common share dividend rate in the fourth quarter of 2017 and first quarter of 2018, as well as an increase in the number of common shares outstanding as a result of common shares issued in connection with the Merger Transaction and the issuance of approximately 33 million common shares in December 2017 in a private placement offering.

Dividend Reinvestment and Share Purchase Plan

Participants in our DRIP receive a 2% discount on the purchase of common shares with reinvested dividends. For the three months ended June 30, 2018 and 2017, dividends declared were $1,145 million and $1,003 million, respectively, of which $729 million and $659 million, respectively, were paid in cash and reflected in financing activities. The remaining $416 million and $344 million, respectively, of dividends paid were reinvested pursuant to the DRIP and resulted in the issuance of common shares rather than a cash payment. For the three months ended June 30, 2018 and 2017, 36.3% and 34.3%, respectively, of total dividends declared were reinvested through the DRIP.

For the six months ended June 30, 2018 and 2017, dividends declared were $1,145 million and $1,551 million, respectively. For the six months ended June 30, 2018 and 2017, total dividends paid were $2,283 million and $1,551 million, respectively, of which $1,493 million and $1,013 million, respectively, were paid in cash and reflected in financing activities. The remaining $790 million and $538 million, respectively, of dividends paid were reinvested pursuant to the DRIP and resulted in the issuance of common shares rather than a cash payment. In addition to amounts paid in cash and reflected in financing activities for the six months ended June 30, 2017, were $414 million in dividends declared to Spectra Energy Corp shareholders prior to the Merger Transaction that were paid after the Merger Transaction. For the six months ended June 30, 2018 and 2017, 34.6% and 34.7%, respectively, of total dividends paid were reinvested through the DRIP.

Our Board of Directors has declared the following quarterly dividends. All dividends are payable on September 1, 2018, to shareholders of record on August 15, 2018.

	Dividend per share
Common Shares	$0.67100
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.21340
Preference Shares, Series C[1]	$0.22748
Preference Shares, Series D[2]	$0.27875
Preference Shares, Series F[3]	$0.29306
Preference Shares, Series H	$0.25000
Preference Shares, Series J	US$0.30540
Preference Shares, Series L	US$0.30993
Preference Shares, Series N	$0.25000
Preference Shares, Series P	$0.25000
Preference Shares, Series R	$0.25000
Preference Shares, Series 1[4]	US$0.37182
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5	US$0.27500
Preference Shares, Series 7	$0.27500
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13	$0.27500
Preference Shares, Series 15	$0.27500
Preference Shares, Series 17	$0.32188
Preference Shares, Series 19[5]	$0.30625

1 *The quarterly dividend per share paid on Series C was increased to $0.22685 from $0.20342 on March 1, 2018, and was increased to $0.22748 from $0.22685 on June 1, 2018, under the dividend rate reset provisions applicable to this series.*
2 *The quarterly dividend per share paid on Series D was increased to $0.27875 from $0.25000 on March 1, 2018, due to reset of the annual dividend on March 1, 2018, under the dividend rate reset provisions applicable to this series.*
3 *The quarterly dividend per share paid on Series F was increased to $0.29306 from $0.25000 on June 1, 2018, due to reset of the annual dividend on June 1, 2018, under the dividend rate reset provisions applicable to this series.*
4 *The quarterly dividend per share paid on Series 1 was increased to US$0.37182 from US$0.25000 on June 1, 2018, due to reset of the annual dividend on June 1, 2018, under the dividend rate reset provisions applicable to this series.*
5 *The dividend per share on Series 19 increased from $0.26850 to the regular quarterly dividend of $0.30625, effective June 1, 2018.*

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Eddystone Rail Legal Matter

In February 2017, our subsidiary Eddystone Rail Company, LLC (Eddystone Rail) filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania. Eddystone Rail alleges that the defendants transferred valuable assets from Eddystone Rail's counterparty in a maritime contract, so as to avoid outstanding obligations to Eddystone Rail. Eddystone Rail is seeking payment of compensatory and punitive damages in excess of US$140 million. On July 19, 2017, the defendants' motions to dismiss Eddystone Rail's claims were denied. Defendants have filed Answers and Counterclaims, which together with subsequent amendments, seek damages from Eddystone Rail in excess of US$32 million. Eddystone filed a motion to dismiss the counterclaims and defendants amended their Answer and Counterclaims on September 21, 2017. On October 12, 2017 Eddystone Rail moved to dismiss the latest version of defendants' counterclaims. On February 6, 2018, the United States District Court for the District of Columbia (the Court) denied without prejudice Eddystone Rail's motion to dismiss the defendants' counterclaims. The defendants' chances of success on their counterclaims cannot be predicted at this time.

Dakota Access Pipeline
In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe (the Tribes) filed motions with the Court contesting the validity of the process used by the Army Corps to permit DAPL. The plaintiffs requested the Court order the operator to shut down the pipeline until the appropriate regulatory process is completed.

On June 14, 2017, the Court ruled that the Army Corps did not sufficiently weigh the degree to which the project's effects would be highly controversial and the Army Corps failed to adequately consider the impact of an oil spill on the hunting and fishing rights of the Tribes and on environmental justice (the June 2017 Order). The Court ordered the Army Corps to reconsider those components of its environmental analysis. On October 11, 2017, the Court issued an order that allows DAPL to continue operating while the Army Corps completes the additional environmental review required by the June 2017 Order. The Court additionally ordered DAPL to implement certain interim measures pending the Army Corps' supplemental analysis. The Army Corps has met with all of the Tribes and its review of appropriate information is underway. The Army Corps' decision on the supplemental analysis is expected during August 2018.

Seaway Pipeline Regulatory Matters
Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011 and refiled in December 2014. Several parties filed comments in opposition alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. On December 1, 2016, the Administrative Law Judge issued its decision which concluded that the Commission should grant the application of Seaway Pipeline for authority to charge market-based rates. By order dated May 17, 2017, the Commission affirmed the Administrative Law Judge’s finding that Seaway Pipeline lacks market power in the applicable markets and granted Seaway Pipeline’s application for market based rate authority. The deadline for shippers to request rehearing of the Commission order was June 18, 2018. No requests for rehearing were filed. The deadline for filing a petition for review of the Commission order with the DC Circuit Court is July 16, 2018. No petitions were filed, so the Commission's decision to grant Seaway Pipeline market based rate authority is now final.

GAS TRANSMISSION AND MIDSTREAM
Sabal Trail FERC Certificate Review
Sierra Club and two other non-governmental organizations filed a Petition for Review of Sabal Trail’s FERC certificate on September 20, 2016 in the D.C. Circuit Court of Appeals. On August 22, 2017, the D.C. Circuit issued an opinion denying one of the petitions, and granting the other petition in part, vacating the certificates, and remanding the case to FERC to supplement the environmental impact statement for the project to estimate the quantity of green-house gases to be released into the environment by the gas-fired generation plants in Florida that will consume the gas transported by Sabal Trail. The court withheld issuance of the mandate requiring vacatur of the certificate until seven days after the disposition of any timely petition for rehearing. On October 6, 2017, Sabal Trail and FERC each filed timely petitions for rehearing. On January 31, 2018, the court denied FERC’s and Sabal Trail’s petitions for rehearing. On February 5, 2018, FERC issued its final supplemental environmental impact statement in compliance with the D.C. Circuit decision. In addition, on February 6, 2018, FERC filed a motion with the court requesting a 45-day stay of the mandate. On March 7, 2018, the court granted FERC’s 45-day request for stay, and directed that issuance of the mandate be withheld through March 26, 2018. On March 14, 2018 FERC issued its Order on Remand Reinstating Certificate and Abandonment Authorizations which addressed the court’s ruling in the August 22, 2017 decision, and on March 30, 2018 the court issued its mandate.

Sierra Club and two other non-governmental organizations, as well as the two landowners, timely requested rehearing from FERC of the March 14, 2018 Order. These requests for rehearing are currently pending before the FERC.

GAS DISTRIBUTION

On July 3, 2018, the government of Ontario issued a regulation which revoked the Cap and Trade program regulation and prohibits registered participants from purchasing, selling, trading or otherwise dealing with emission allowances and credits. Subsequently, on July 6, 2018, the Ontario Energy Board (OEB) suspended its review of EGD and Union Gas' 2018 Cap and Trade Compliance Plans. EGD and Union Gas continue to collect cap and trade unit rates from customers pursuant to the OEB's Decision and Order dated November 30, 2017. At this time, the details of how the government of Ontario will complete the wind down of the Cap and Trade program have yet to be announced. The impact to us from the change in regulation is still being evaluated but is not expected to be material. EGD and Union Gas continue to monitor policy developments and work with both the OEB and government of Ontario to remain compliant with future direction related to the Cap and Trade program.

OTHER LITIGATION

We and our subsidiaries are involved in 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 our consolidated financial position or results of operations.

CAPITAL EXPENDITURE COMMITMENTS

We have signed contracts for the purchase of services, pipe and other materials totaling $3,322 million which are expected to be paid over the next five years.

TAX MATTERS

We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

CHANGES IN ACCOUNTING POLICIES

Refer to Item 1. *Financial Statements - Note 2. Changes in Accounting Policies.*

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk is described in Part II. Item 7A. *Quantitative and Qualitative Disclosures About Market Risk* of our Annual Report on Form 10-K for the fiscal year ended December 31, 2017, filed with the SEC on February 16, 2018. We believe our exposure to market risk has not changed materially since then.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to provide reasonable assurance that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2018, and based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in ensuring that information required to be disclosed by us in reports that we file with or submit to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

Changes in Internal Control over Financial Reporting
Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended June 30, 2018 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are involved in various legal and regulatory actions and proceedings which arise in the ordinary course of business. 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 our consolidated financial position or results of operations. Refer to Part I. Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* for discussion of other legal proceedings.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, careful consideration should be given to the factors discussed in Part I. Item 1A. *Risk Factors* of our Annual Report on Form 10-K for the year ended December 31, 2017, which could materially affect our financial condition or future results. Other than as set out below, there have been no modifications to those risk factors.

Our operations are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Many of our operations are regulated. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States have changed significantly in past years and further substantial changes may occur.

On February 8, 2018, the Government of Canada introduced legislation to revise the process for assessing major resource projects. If the legislation is passed in its current form, we believe it would have adverse impacts on pipeline companies, particularly in relation to the regulatory review process for proposed new projects that are “designated projects”, by making overall timelines for the development and execution of these projects longer and significantly increasing uncertainty.

Compliance with legislative changes may impose additional costs on new pipeline projects as well as on existing operations. Failure to comply with applicable regulations could result in a number of consequences which may have an adverse effect on our operations, earnings, financial condition and cash flows.

There can be no assurance that the proposed combination transactions between us and our sponsored vehicles will be agreed upon, approved and ultimately consummated, and the terms of any such transactions may differ materially from those originally proposed by us.

On May 17, 2018, we made separate non-binding all-share proposals to the respective boards of directors of our sponsored vehicles, SEP, EEP, EEQ and ENF, to acquire, in separate combination transactions, all of the outstanding equity securities of those sponsored vehicles not beneficially owned by us. Under the original proposals:

- SEP unitholders would receive 1.0123 common shares of Enbridge per SEP unit;
- EEP unitholders would receive 0.3083 common shares of Enbridge per EEP unit;
- EEQ shareholders would receive 0.2887 common shares of Enbridge per EEQ share; and
- ENF shareholders would receive 0.7029 common shares of Enbridge per ENF share.

Each of the proposals above are subject to negotiation. Any definitive agreements with respect to any of the proposals is subject to approval by our board of directors and to applicable sponsored vehicle board and unitholder approvals. Such definitive agreements would be expected to contain customary closing conditions, including standard regulatory notifications and approvals.

We cannot predict whether the terms of any of the potential transactions will be agreed upon by us and the SEP, EEP, EEQ or ENF conflicts committees or special committees, as applicable, or whether any such transactions would be approved by the requisite votes of securityholders of the respective sponsored vehicles. We also cannot predict the timing, final structure and other terms of any of the potential transactions, and the terms of any such transactions may differ materially from those originally proposed by us. Any changes in the market prices of our common shares or the units or shares, as applicable, of the sponsored vehicles could affect whether our board of directors, the sponsored vehicle conflicts or special committees, as applicable, and the securityholders of the applicable sponsored vehicle ultimately approve the proposed transactions, or if such approval is granted, the terms on which the proposed transactions are approved.

Uncertainties about the effect of the proposed transactions may have an adverse effect on us. These uncertainties may have negative impacts on the market price of our common shares, our businesses and financial results.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Each exhibit identified below is included as a part of this quarterly report. Exhibits included in this filing are designated by an asterisk ("*"); all exhibits not so designated are incorporated by reference to a prior filing as indicated.

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of September 5, 2016, by and among Spectra Energy Corp, Enbridge Inc. and Sand Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

SIGNATURES

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

ENBRIDGE INC.
(Registrant)

Date: August 3, 2018

By: /s/ Al Monaco

Al Monaco
President and Chief Executive Officer

Date: August 3, 2018

By: /s/ John K. Whelen

John K. Whelen
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

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