ENBRIDGE

ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

September 30, 2018

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(unaudited; millions of Canadian dollars, except per share amounts)				
Operating revenues				
Commodity sales	**6,919**	5,012	**20,638**	18,498
Gas distribution sales	**478**	573	**3,260**	2,783
Transportation and other services	**3,948**	3,642	**10,918**	10,208
Total operating revenues *(Note 3)*	**11,345**	9,227	**34,816**	31,489
Operating expenses				
Commodity costs	**6,905**	5,087	**20,180**	18,126
Gas distribution costs	**112**	215	**1,857**	1,659
Operating and administrative	**1,652**	1,587	**4,929**	4,784
Depreciation and amortization	**799**	848	**2,452**	2,388
Asset impairment *(Note 6)*	**4**	—	**1,076**	—
Goodwill impairment *(Note 6)*	**1,019**	—	**1,019**	—
Total operating expenses	**10,491**	7,737	**31,513**	26,957
Operating income	**854**	1,490	**3,303**	4,532
Income from equity investments	**378**	280	**1,076**	752
Other income/(expense)				
Net foreign currency gain/(loss)	**57**	150	**(171)**	257
Other	**(33)**	75	**61**	182
Interest expense	**(696)**	(653)	**(2,042)**	(1,704)
Earnings before income taxes	**560**	1,342	**2,227**	4,019
Income tax expense *(Note 12)*	**(347)**	(327)	**(177)**	(818)
Earnings	**213**	1,015	**2,050**	3,201
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(209)**	(168)	**(352)**	(633)
Earnings attributable to controlling interests	**4**	847	**1,698**	2,568
Preference share dividends	**(94)**	(82)	**(272)**	(246)
Earnings/(loss) attributable to common shareholders	**(90)**	765	**1,426**	2,322
Earnings/(loss) per common share attributable to common shareholders *(Note 5)*	**(0.05)**	0.47	**0.84**	1.57
Diluted earnings/(loss) per common share attributable to common shareholders *(Note 5)*	**(0.05)**	0.47	**0.84**	1.56

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(unaudited; millions of Canadian dollars)				
Earnings	**213**	1,015	**2,050**	3,201
Other comprehensive income/(loss), net of tax				
Change in unrealized gain on cash flow hedges	**57**	97	**150**	10
Change in unrealized gain/(loss) on net investment hedges	**83**	285	**(200)**	505
Other comprehensive income from equity investees	**(1)**	1	**18**	9
Reclassification to earnings of (gain)/loss on cash flow hedges	**31**	(14)	**104**	93
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**5**	6	**28**	13
Foreign currency translation adjustments	**(989)**	(2,057)	**1,637**	(3,068)
Other comprehensive income/(loss), net of tax	**(814)**	(1,682)	**1,737**	(2,438)
Comprehensive income/(loss)	**(601)**	(667)	**3,787**	763
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**(102)**	155	**(546)**	(204)
Comprehensive income/(loss) attributable to controlling interests	**(703)**	(512)	**3,241**	559
Preference share dividends	**(94)**	(82)	**(272)**	(246)
Comprehensive income/(loss) attributable to common shareholders	**(797)**	(594)	**2,969**	313

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Nine months ended September 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	**1,181**	889
Shares issued on exercise of stock options	**26**	58
Balance at end of period	**51,944**	48,868
Additional paid-in capital		
Balance at beginning of period	**3,194**	3,399
Stock-based compensation	**40**	70
Fair value of outstanding earned stock-based compensation from Merger Transaction	**—**	77
Options exercised	**(14)**	(70)
Enbridge Energy Company, Inc. common control transaction	**—**	78
Dilution loss on Enbridge Energy Partners, L.P. issuance of Class A units	**—**	(522)
Dilution gain on Spectra Energy Partners, LP restructuring *(Note 10)*	**1,136**	—
Dilution gains/(losses) and other	**(89)**	62
Sale of noncontrolling interests in subsidiaries *(Note 10)*	**79**	—
Balance at end of period	**4,346**	3,094
Deficit		
Balance at beginning of period	**(2,468)**	(716)
Earnings attributable to controlling interests	**1,698**	2,568
Preference share dividends	**(272)**	(246)
Common share dividends declared	**(2,297)**	(2,552)
Dividends paid to reciprocal shareholder	**25**	22
Modified retrospective adoption of accounting standard *(Note 2)*	**(86)**	—
Redemption value adjustment attributable to redeemable noncontrolling interests	**(318)**	232
Adjustment for the recognition of unutilized tax deductions for stock-based compensation expense	**—**	41
Balance at end of period	**(3,718)**	(651)
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	**1,543**	(2,009)
Balance at end of period	**570**	(951)
Reciprocal shareholding		
Balance at beginning and end of period	**(102)**	(102)
Total Enbridge Inc. shareholders' equity	**60,787**	57,513
Noncontrolling interests		
Balance at beginning of period	**7,597**	577
Earnings attributable to noncontrolling interests	**248**	452
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax		
Change in unrealized gain/(loss) on cash flow hedges	**8**	(13)
Foreign currency translation adjustments	**140**	(446)
Reclassification to earnings of loss on cash flow hedges	**23**	29
	171	(430)
Comprehensive income attributable to noncontrolling interests	**419**	22
Noncontrolling interests resulting from Merger Transaction	**—**	8,877
Enbridge Energy Company, Inc. common control transaction	**—**	(331)
Dilution gain on Enbridge Energy Partners, L.P. issuance of Class A units	**—**	832
Spectra Energy Partners, LP restructuring *(Note 10)*	**(1,486)**	—
Sale of noncontrolling interests in subsidiaries *(Note 10)*	**1,183**	—
Distributions	**(637)**	(634)
Contributions	**23**	498
Deconsolidation of Sabal Trail Transmission, LLC	**—**	(2,318)
Disposition of Olympic Pipeline	**—**	(24)
Other	**12**	(16)
Balance at end of period	**7,111**	7,483
Total equity	**67,898**	64,996
Dividends paid per common share	**2.013**	1.803

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine months ended September 30,	
	2018	2017
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**2,050**	3,201
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**2,452**	2,388
Deferred income tax (recovery)/expense	**(51)**	725
Changes in unrealized (gain)/loss on derivative instruments, net *(Note 11)*	**319**	(1,243)
Earnings from equity investments	**(1,076)**	(752)
Distributions from equity investments	**1,090**	859
Asset impairment	**1,076**	—
Goodwill impairment	**1,019**	—
(Gain)/loss on dispositions	**76**	(116)
Other	**101**	132
Changes in operating assets and liabilities	**943**	121
Net cash provided by operating activities	**7,999**	5,315
Investing activities		
Capital expenditures	**(4,584)**	(5,868)
Long-term investments	**(1,051)**	(3,012)
Distributions from equity investments in excess of cumulative earnings *(Note 7)*	**1,243**	62
Additions to intangible assets	**(491)**	(668)
Cash acquired in Merger Transaction	**—**	681
Proceeds from dispositions	**1,913**	622
Reimbursement of capital expenditures	**—**	212
Other	**(102)**	(63)
Net cash used in investing activities	**(3,072)**	(8,034)
Financing activities		
Net change in short-term borrowings	**(196)**	705
Net change in commercial paper and credit facility draws	**(2,358)**	956
Debenture and term note issues, net of issue costs	**3,537**	7,176
Debenture and term note repayments	**(3,757)**	(4,446)
Sale of noncontrolling interest in subsidiaries	**1,289**	—
Purchase of interest in consolidated subsidiary	**—**	(227)
Contributions from noncontrolling interests	**23**	498
Distributions to noncontrolling interests	**(637)**	(714)
Contributions from redeemable noncontrolling interests	**62**	614
Distributions to redeemable noncontrolling interests	**(264)**	(180)
Common shares issued	**17**	22
Preference share dividends	**(268)**	(246)
Common share dividends	**(2,254)**	(2,077)
Other	**(5)**	—
Net cash provided by/(used in) financing activities	**(4,811)**	2,081
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**23**	(77)
Net increase/(decrease) in cash and cash equivalents and restricted cash	**139**	(715)
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	**726**	847

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2018	December 31, 2017
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**643**	480
Restricted cash	**83**	107
Accounts receivable and other	**5,668**	7,053
Accounts receivable from affiliates	**75**	47
Inventory	**1,362**	1,528
	7,831	9,215
Property, plant and equipment, net	**90,679**	90,711
Long-term investments	**15,983**	16,911
Deferred amounts and other assets	**10,638**	6,442
Intangible assets, net	**3,273**	3,267
Goodwill	**33,477**	34,457
Deferred income taxes	**1,342**	1,090
Total assets	**163,223**	162,093
Liabilities and equity		
Current liabilities		
Short-term borrowings	**1,251**	1,444
Accounts payable and other	**7,599**	9,518
Accounts payable to affiliates	**190**	157
Interest payable	**611**	634
Current portion of long-term debt	**3,516**	2,871
	13,167	14,624
Long-term debt	**58,707**	60,865
Other long-term liabilities	**9,090**	7,510
Deferred income taxes	**10,040**	9,295
	91,004	92,294
Contingencies *(Note 14)*		
Redeemable noncontrolling interests	**4,321**	4,067
Equity		
Share capital		
Preference shares	**7,747**	7,747
Common shares *(1,794 and 1,695 outstanding at September 30, 2018 and December 31, 2017, respectively)*	**51,944**	50,737
Additional paid-in capital	**4,346**	3,194
Deficit	**(3,718)**	(2,468)
Accumulated other comprehensive income/(loss) *(Note 9)*	**570**	(973)
Reciprocal shareholding	**(102)**	(102)
Total Enbridge Inc. shareholders' equity	**60,787**	58,135
Noncontrolling interests	**7,111**	7,597
	67,898	65,732
Total liabilities and equity	**163,223**	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.

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 nine months ended September 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.

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 allowed a reclassification from accumulated other comprehensive income (AOCI) to retained earnings for stranded tax effects resulting from the TCJA. The amendments eliminated the stranded tax effects recognized 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. For the three and nine months ended September 30, 2018, the effect of the adoption of ASC 606 on our Consolidated Statement of Earnings was not material.

(millions of Canadian dollars)	Balance at December 31, 2017	Adjustments Due to ASC 606	Balance at January 1, 2018
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

Amended Guidance on Cloud Computing Arrangements

In August 2018, ASU 2018-15 was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement (CCA) that is a service contract. The amendment aligns the accounting for costs incurred to implement a CCA that is a service arrangement with the guidance on capitalizing costs associated with developing or obtaining internal-use software. Additionally, ASU 2018-15 specifies that an entity would apply ASC 350-40, Internal-use software, to determine which implementation costs related to a hosting arrangement that is a service contract should be capitalized and which should be expensed. Furthermore, the amendments in the update require capitalized costs be amortized on a straight-line basis generally over the term of the arrangement and presented in the same income statement line as fees paid for the hosting service. The new standard also requires that the balance sheet presentation of capitalized implementation costs to be the same as that of the prepayment of fees related to the hosting arrangement, as well as similar consistency in classifications from a cash flow statement perspective. ASU 2018-15 is effective January 1, 2020 and early adoption is permitted. We are currently assessing the impact of the new standard on our consolidated financial statements.

Disclosure Effectiveness

In August 2018, the Financial Accounting Standards Board issued two amendments as a part of its disclosure framework project aimed to improve the effectiveness of disclosures in the notes to financial statements.

ASU 2018-14 was issued in August 2018 to improve disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. The amendment modifies the current guidance by adding and removing several disclosure requirements while also clarifying the guidance on current disclosure requirements. ASU 2018-14 is effective January 1, 2021 and entities are permitted to adopt the standard early. We are currently assessing the impact of the new standard on our consolidated financial statements.

ASU 2018-13 was issued to improve the disclosure requirements for fair value measurements by eliminating and modifying some disclosures, while also adding new disclosures. This update is effective January 1, 2020, however entities are permitted to early adopt the eliminated or modified disclosures. We are currently assessing the impact of the new standard on our consolidated financial statements.

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 also permits entities not to reassess a) whether any expired or existing contracts contain leases in accordance with the new guidance, b) lease classifications, and c) whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance.

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.

In July 2018, ASU 2018-11 was issued to address additional stakeholder concerns regarding the unanticipated costs and complexities associated with the modified retrospective transition method as well as the requirement for lessors to separate components of a contract. Under the new guidance, entities are provided with an additional transition method which allows entities to apply the new standard at the date of adoption and to elect not to recast comparative periods presented. This amendment also provides a practical expedient which allows lessors to combine associated lease and nonlease components within a contract when certain conditions are met. We intend to adopt the new transition option in connection with the adoption of the new lease requirements; however we continue to evaluate the lessor practical expedient to combine lease and nonlease components.

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 change to our financial statements will be the recognition of lease liabilities and right-of-use assets in our statement of financial position 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 September 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	2,190	979	97	—	—	—	**3,266**
Storage and other revenue	31	53	55	—	—	—	**139**
Gas gathering and processing revenue	—	200	—	—	—	—	**200**
Gas distribution revenue	—	—	478	—	—	—	**478**
Electricity and transmission revenue	—	—	—	115	—	—	**115**
Commodity sales	—	298	—	—	—	—	**298**
Total revenue from contracts with customers	2,221	1,530	630	115	—	—	**4,496**
Commodity sales	—	—	—	—	6,621	—	**6,621**
Other revenue[1]	222	(6)	11	2	—	(1)	**228**
Intersegment revenue	86	4	4	—	25	(119)	**—**
Total revenue	**2,529**	**1,528**	**645**	**117**	**6,646**	**(120)**	**11,345**

Nine months ended September 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	6,327	2,889	487	—	—	—	**9,703**
Storage and other revenue	113	164	173	—	—	—	**450**
Gas gathering and processing revenue	—	636	—	—	—	—	**636**
Gas distribution revenue	—	—	3,260	—	—	—	**3,260**
Electricity and transmission revenue	—	—	—	417	—	—	**417**
Commodity sales	—	1,630	—	—	—	—	**1,630**
Total revenue from contracts with customers	6,440	5,319	3,920	417	—	—	**16,096**
Commodity sales	—	—	—	—	19,008	—	**19,008**
Other revenue[1]	(308)	2	22	6	—	(10)	**(288)**
Intersegment revenue	256	8	10	—	106	(380)	**—**
Total revenue	**6,388**	**5,329**	**3,952**	**423**	**19,114**	**(390)**	**34,816**

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 September 30, 2018	1,625	267	1,203

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 nine months ended September 30, 2018 included in contract liabilities at the beginning of the period is $19 million and $143 million, respectively. Increases in contract liabilities from cash received, net of amounts recognized as revenue during the three and nine months ended September 30, 2018 were $147 million and $345 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 nine months ended September 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 $64.7 billion, of which $1.7 billion and $5.8 billion is expected to be recognized during the three months ending December 31, 2018, and the 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 September 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]	—	298	20	—	—	**318**
Revenue from products and services transferred over time[2]	2,221	1,232	610	115	—	**4,178**
Total revenue from contracts with customers	**2,221**	**1,530**	**630**	**115**	**—**	**4,496**

Nine months ended September 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]	—	1,630	65	—	—	**1,695**
Revenue from products and services transferred over time[2]	6,440	3,689	3,855	417	—	**14,401**
Total revenue from contracts with customers	**6,440**	**5,319**	**3,920**	**417**	**—**	**16,096**

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 September 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	**2,529**	**1,528**	**645**	**117**	**6,646**	**(120)**	**11,345**
Commodity and gas distribution costs	**(5)**	**(270)**	**(137)**	**—**	**(6,726)**	**121**	**(7,017)**
Operating and administrative	**(790)**	**(519)**	**(263)**	**(38)**	**(17)**	**(25)**	**(1,652)**
Asset impairment	**—**	**—**	**—**	**(4)**	**—**	**—**	**(4)**
Goodwill impairment	**—**	**(1,019)**	**—**	**—**	**—**	**—**	**(1,019)**
Income/(loss) from equity investments	**131**	**262**	**(12)**	**(6)**	**3**	**—**	**378**
Other income/(expense)	**10**	**(42)**	**23**	**(18)**	**(2)**	**53**	**24**
Earnings/(loss) before interest, income taxes, and depreciation and amortization	**1,875**	**(60)**	**256**	**51**	**(96)**	**29**	**2,055**
Depreciation and amortization							**(799)**
Interest expense							**(696)**
Income tax expense							**(347)**
Earnings							**213**
Capital expenditures[1]	**651**	**413**	**311**	**6**	**—**	**(19)**	**1,362**

Three months ended September 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	2,324	1,862	716	109	4,284	(68)	9,227
Commodity and gas distribution costs	(5)	(703)	(242)	1	(4,421)	68	(5,302)
Operating and administrative	(770)	(498)	(246)	(42)	(11)	(20)	(1,587)
Income/(loss) from equity investments	118	162	(3)	—	3	—	280
Other income/(expense)	36	33	15	—	(5)	146	225
Earnings/(loss) before interest, income taxes, and depreciation and amortization	1,703	856	240	68	(150)	126	2,843
Depreciation and amortization							(848)
Interest expense							(653)
Income tax expense							(327)
Earnings							1,015
Capital expenditures[1]	529	1,052	302	64	—	22	1,969

Nine months ended September 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	**6,388**	**5,329**	**3,952**	**423**	**19,114**	**(390)**	**34,816**
Commodity and gas distribution costs	**(14)**	**(1,481)**	**(1,969)**	**—**	**(18,965)**	**392**	**(22,037)**
Operating and administrative	**(2,251)**	**(1,560)**	**(782)**	**(104)**	**(50)**	**(182)**	**(4,929)**
Asset impairment	**(154)**	**(913)**	**—**	**(4)**	**—**	**(5)**	**(1,076)**
Goodwill impairment	**—**	**(1,019)**	**—**	**—**	**—**	**—**	**(1,019)**
Income/(loss) from equity investments	**399**	**699**	**(5)**	**(27)**	**10**	**—**	**1,076**
Other income/(expense)	**(15)**	**25**	**66**	**(2)**	**(1)**	**(183)**	**(110)**
Earnings/(loss) before interest, income taxes, and depreciation and amortization	**4,353**	**1,080**	**1,262**	**286**	**108**	**(368)**	**6,721**
Depreciation and amortization							**(2,452)**
Interest expense							**(2,042)**
Income tax expense							**(177)**
Earnings							**2,050**
Capital expenditures[1]	**1,776**	**2,105**	**733**	**30**	**—**	**(11)**	**4,633**

Nine months ended September 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	6,722	5,051	3,322	386	16,272	(264)	31,489
Commodity and gas distribution costs	(13)	(2,053)	(1,740)	4	(16,251)	268	(19,785)
Operating and administrative	(2,214)	(1,305)	(676)	(123)	(34)	(432)	(4,784)
Income from equity investments	312	427	10	2	5	(4)	752
Other income/(expense)	33	143	21	1	(3)	244	439
Earnings/(loss) before interest, income taxes, and depreciation and amortization	4,840	2,263	937	270	(11)	(188)	8,111
Depreciation and amortization							(2,388)
Interest expense							(1,704)
Income tax expense							(818)
Earnings							3,201
Capital expenditures[1]	1,723	3,081	794	293	1	90	5,982

1 Includes allowance for equity funds used during construction.

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 nine months ended September 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 September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(number of common shares in millions)				
Weighted average shares outstanding	**1,705**	1,635	**1,695**	1,482
Effect of dilutive options	**3**	7	**4**	8
Diluted weighted average shares outstanding	**1,708**	1,642	**1,699**	1,490

For the three months ended September 30, 2018 and 2017, 21,081,642 and 12,917,175, respectively, anti-dilutive stock options with a weighted average exercise price of $52.17 and $56.79, respectively, were excluded from the diluted earnings per common share calculation.

For the nine months ended September 30, 2018 and 2017, 27,069,810 and 13,293,044, respectively, anti-dilutive stock options with a weighted average exercise price of $50.37 and $57.50, respectively, were excluded from the diluted earnings per common share calculation.

6. ACQUISITIONS AND DISPOSITIONS

ASSETS HELD FOR SALE

Canadian Natural Gas Gathering and Processing Businesses

On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners for a cash purchase price of approximately $4.3 billion, subject to customary closing adjustments. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations (collectively, Canadian Natural Gas Gathering and Processing Businesses assets). On October 1, 2018, we closed the sale of the provincially regulated facilities for proceeds of approximately $2.5 billion. These assets were included within our Gas Transmission and Midstream segment. The sale of the federally regulated facilities is expected to close in mid-2019 for proceeds of approximately $1.8 billion.

During the third quarter of 2018, we classified the Canadian Natural Gas Gathering and Processing Businesses assets as held for sale. As these assets represented a portion of a reporting unit, we allocated a portion of the goodwill of the reporting unit to these assets using a relative fair value approach. As a result of the goodwill allocation, the carrying value of Canadian Natural Gas Gathering and Processing Businesses assets is greater than the sale price consideration less the cost to sell. Therefore, we recorded a goodwill impairment of $1,019 million on the Consolidated Statements of Earnings for the three and nine months ended September 30, 2018. Further, the held for sale classification represented a triggering event and required us to perform a goodwill impairment test for the related reporting unit. The results of the test did not indicate any additional goodwill impairment.

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. (EEP), 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 nine months ended September 30, 2018.

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

	September 30, 2018	December 31, 2017
(millions of Canadian dollars)		
Accounts receivable and other (current assets held for sale)	**154**	424
Deferred amounts and other assets (long-term assets held for sale)[1]	**4,841**	1,190
Accounts payable and other (current liabilities held for sale)	**(70)**	(315)
Other long-term liabilities (long-term liabilities held for sale)[2]	**(430)**	(34)
Net assets held for sale	**4,495**	1,265

1 Included within Deferred amounts and other assets at September 30, 2018, is property, plant and equipment of $4.1 billion and goodwill of $482 million. Included within Deferred amounts and other assets at December 31, 2017, is property, plant and equipment of $1.1 billion.

2 Included within Other long-term liabilities at September 30, 2018 are deferred tax liabilities of $329 million.

DISPOSITIONS

Renewable Assets

On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets, a 49% interest in two 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) to the Canada Pension Plan Investment Board (CPPIB). Total cash proceeds from the transaction were $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 will continue to manage, operate and provide administrative services for these assets.

A loss on disposal of $20 million (€14 million) was included in Other income/(expense) in the Consolidated Statements of Earnings for the sale of 49% of our interest in the Hohe See Offshore wind farm and its subsequent expansion. Subsequent to the sale, the remaining interests in these assets continue to be accounted for as an equity method investment, and are a part of our Green Power and Transmission segment.

Gains of $62 million and $17 million (US$13 million) were included in Additional paid-in capital in the Consolidated Statements of Financial Position for the sale of 49% interest in the Canadian and United States renewable assets, respectively. Subsequent to the sale, because we maintained a controlling interest, these assets continue to be consolidated and are a part of our Green Power and Transmission segment. In addition, we recognized noncontrolling interests in our Consolidated Statements of Financial Position as at September 30, 2018 to reflect the interests that we do not hold *(Note 10)*.

Also, a deferred income tax recovery of $267 million ($196 million attributable to us) was recorded in the nine months ended September 30, 2018 as a result of the agreement entered into during the second quarter of 2018 for the Renewable Assets *(Note 12)*.

In connection with our sale of the Renewable Assets, we have new consolidated and unconsolidated variable interest entities (VIEs) *(Note 7)*.

Midcoast Operating, L.P.

On August 1, 2018, our indirect subsidiary, Enbridge (U.S.) Inc. closed the sale of Midcoast Operating, L.P. and its subsidiaries (collectively, MOLP) to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC) for total cash proceeds of $1.4 billion (US$1.1 billion). A loss on disposal of $74 million (US$57 million) was included in Other income/(expense) in the Consolidated Statements of Earnings. 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.

Upon closing of the sale, we also recorded a liability of $387 million (US$298 million) for future volume commitments retained by us. The associated loss is included in the loss on disposal of $74 million discussed above. As at September 30, 2018, $75 million (US$58 million) and $306 million (US$237 million) were included in Accounts payable and other and Other long-term liabilities, respectively, on the Consolidated Statements of Financial Position.

In the second quarter of 2018, our equity method investment in the Texas Express NGL pipeline system, together with the MOLP assets that have been held for sale since December 31, 2017, 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.

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 nine months ended September 30, 2018.

7. VARIABLE INTEREST ENTITIES

In connection with our sale of the Renewable Assets *(Note 6)*, we have new consolidated and unconsolidated VIEs.

CONSOLIDATED VARIABLE INTEREST ENTITY

Enbridge Canadian Renewable LP (ECRLP)

To facilitate the sale on August 1, 2018, we and our subsidiaries transferred our Canadian renewable assets to a newly formed partnership, ECRLP. Subsequently, a 49% interest in ECRLP was sold to CPPIB. ECRLP is a VIE as its limited partners do not have substantive kick-out rights or participating rights. Because we have the power to direct the activities of ECRLP, we are exposed to potential losses, and we have the right to receive benefits from ECRLP, we are considered the primary beneficiary. We consolidate the VIE because of our indirect controlling financial interest in the VIE.

As at September 30, 2018, the carrying amounts of total assets and liabilities of ECRLP on our Consolidated Statements of Financial Position were $2.1 billion and $45 million, respectively. The creditors of the VIE do not have recourse to our general credit, other than through nominal assets of the holding company with the general partnership interest. We did not provide any additional financial support to ECRLP during the nine months ended September 30, 2018.

UNCONSOLIDATED VARIABLE INTEREST ENTITY

Enbridge Renewable Infrastructure Investments S.a.r.l. (ERII)

To facilitate the sale on August 1, 2018, we transferred our interest in the Hohe See Offshore wind farm and its subsequent expansion to a newly formed partnership, ERII. Subsequently, a 49% interest in ERII was sold to CPPIB. ERII is a VIE due to insufficient equity at risk to finance its activities. We are not the primary beneficiary of ERII since the power to direct the activities of ERII that most significantly impact its economic performance is shared. We account for ERII by using the equity method as we retain significant influence through a 51% voting interest in substantive decisions.

ERII has a carrying value of $118 million (€79 million) at September 30, 2018, within Long-term investments in our Consolidated Statements of Financial Position. Included within Deferred amounts and other assets in our Consolidated Statements of Financial Position at September 30, 2018, is a long-term receivable of $416 million (€277 million) relating to our loan to a consolidated subsidiary of ERII. The maximum exposure to loss as a result of our involvement with ERII is $534 million (€356 million), which is equal to the long-term investment carrying value plus the outstanding receivable discussed above.

OTHER

Sabal Trail Transmission, LLC

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 members as a partial reimbursement of construction and development costs incurred by the members. 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 nine months ended September 30, 2018. These events triggered reconsideration and as a result, it was concluded that Sabal Trail was no longer a VIE as at June 30, 2018 due to sufficient equity at risk to finance its activities.

8. DEBT

CREDIT FACILITIES

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

		September 30, 2018		
	Maturity	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2019-2023	**5,602**	**2,330**	**3,272**
Enbridge (U.S.) Inc.	2019	**1,829**	**—**	**1,829**
Enbridge Energy Partners, L.P.[2]	2019-2022	**3,167**	**2,210**	**957**
Enbridge Gas Distribution Inc. (EGD)	2019-2020	**1,017**	**779**	**238**
Enbridge Income Fund	2020	**1,500**	**9**	**1,491**
Enbridge Pipelines Inc.	2020	**3,000**	**1,214**	**1,786**
Spectra Energy Partners, LP[3]	2022	**3,232**	**2,153**	**1,079**
Union Gas Limited (Union Gas)	2021	**700**	**481**	**219**
Total committed credit facilities		**20,047**	**9,176**	**10,871**

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

2 Includes $239 million (US$185 million) of commitments that expire in 2020.

3 Includes $435 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 scheduled 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 scheduled to mature in 2019, and repaid drawn amounts. In addition, Enbridge (U.S.) Inc. terminated an unutilized US$950 million credit facility, which was scheduled 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 scheduled to mature in 2021.

In addition to the committed credit facilities noted above, we maintain $790 million of uncommitted demand credit facilities, of which $564 million were unutilized as at September 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 scheduled to mature from 2019 to 2023.

As at September 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 $7,534 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 nine months ended September 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 subordinated notes due 2078[1]	US$850
	April 2018	Fixed-to-floating rate subordinated notes due 2078[2]	$750
	April 2018	Fixed-to-floating rate subordinated 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 nine months ended September 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	
	July 2018	4.01% medium-term notes due June 2040	$8	
Midcoast Energy Partners, L.P.				
Redemption[2]				
	July 2018	3.56% senior notes due September 2019	US$75	US$76
	July 2018	4.04% senior notes due September 2021	US$175	US$182
	July 2018	4.42% senior notes due September 2024	US$150	US$161
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	
	July 2018	6.75% senior notes	US$118	
Spectra Energy Partners, LP				
	September 2018	2.95% senior notes	US$500	
Union Gas Limited				
	April 2018	5.35% medium-term notes	$200	
	August 2018	8.75% debenture	$125	
Westcoast Energy Inc.				
	May 2018	6.90% senior secured notes	$13	
	May 2018	4.34% senior secured notes	$4	
	September 2018	8.50% debenture	$150	

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

2 The loss on debt extinguishment of $64 million (US$50 million), net of a fair value adjustment recorded upon completion of the Merger Transaction, was reported within Interest expense in the Consolidated Statements of Earnings.

SUBORDINATED TERM NOTES

As at September 30, 2018 and December 31, 2017, our fixed-to-floating subordinated term notes had a principal value of $7,053 million and $4,344 million, respectively.

FAIR VALUE ADJUSTMENT

As at September 30, 2018, the net fair value adjustment for total debt assumed in the Merger Transaction was $975 million. During the three and nine months ended September 30, 2018, the amortization of the fair value adjustment, recorded as a reduction to Interest expense in the Consolidated Statements of Earnings, was $23 million and $112 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 September 30, 2018, we were in compliance with all debt covenants.

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in AOCI attributable to our common shareholders for the nine months ended September 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	**167**	**(232)**	**1,495**	**(8)**	**—**	**1,422**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**92**	**—**	**—**	**—**	**—**	**92**
Commodity contracts[2]	**(1)**	**—**	**—**	**—**	**—**	**(1)**
Foreign exchange contracts[3]	**6**	**—**	**—**	**—**	**—**	**6**
Other contracts[4]	**10**	**—**	**—**	**—**	**—**	**10**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**—**	**—**	**—**	**—**	**36**	**36**
	274	**(232)**	**1,495**	**(8)**	**36**	**1,565**
Tax impact						
Income tax on amounts retained in AOCI	**(26)**	**32**	**—**	**9**	**—**	**15**
Income tax on amounts reclassified to earnings	**(29)**	**—**	**—**	**—**	**(8)**	**(37)**
	(55)	**32**	**—**	**9**	**(8)**	**(22)**
Balance as at September 30, 2018	**(425)**	**(339)**	**1,572**	**11**	**(249)**	**570**

	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	29	496	(2,616)	(4)	—	(2,095)
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	104	—	—	—	—	104
Commodity contracts[2]	(5)	—	—	—	—	(5)
Foreign exchange contracts[3]	(2)	—	—	—	—	(2)
Other contracts[4]	(3)	—	—	—	—	(3)
Amortization of pension and OPEB actuarial loss and prior service costs[5]	—	—	—	—	21	21
	123	496	(2,616)	(4)	21	(1,980)
Tax impact						
Income tax on amounts retained in AOCI	(9)	9	—	13	—	13
Income tax on amounts reclassified to earnings	(34)	—	—	—	(8)	(42)
	(43)	9	—	13	(8)	(29)
Balance as at September 30, 2017	(666)	(124)	84	46	(291)	(951)

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

Renewable Assets

On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets and a 49% interest in two United States renewable assets to CPPIB *(Note 6)*. As a result, we recorded an increase in Noncontrolling interests, Additional paid-in capital and Deferred income tax liabilities of $1,183 million, $79 million and $27 million, respectively, for the nine months ended September 30, 2018. For the three months ended September 30, 2018, CPPIB's distributions and allocation of earnings were not proportionate to its ownership.

SEP Incentive Distribution Rights

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 tax liabilities of $1.1 billion and $333 million, respectively, for the nine months ended September 30, 2018.

11. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISKS

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 risks). 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 has been 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 amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

September 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	**—**	**1**	**—**	**66**	**67**	**(49)**	**18**
Interest rate contracts	**49**	**—**	**—**	**—**	**49**	**(3)**	**46**
Commodity contracts	**1**	**—**	**—**	**119**	**120**	**(85)**	**35**
	50	**1**	**—**	**185**	**236**	**(137)**	**99**
Deferred amounts and other assets							
Foreign exchange contracts	**4**	**—**	**—**	**39**	**43**	**(29)**	**14**
Interest rate contracts	**42**	**—**	**—**	**—**	**42**	**(1)**	**41**
Commodity contracts	**18**	**—**	**—**	**12**	**30**	**(25)**	**5**
Other contracts	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	64	**—**	**—**	**51**	**115**	**(55)**	**60**
Accounts payable and other							
Foreign exchange contracts	**(5)**	**—**	**—**	**(371)**	**(376)**	**49**	**(327)**
Interest rate contracts	**(50)**	**—**	**(9)**	**(179)**	**(238)**	**3**	**(235)**
Commodity contracts	**—**	**—**	**—**	**(411)**	**(411)**	**85**	**(326)**
Other contracts	**(1)**	**—**	**—**	**(8)**	**(9)**	**—**	**(9)**
	(56)	**—**	**(9)**	**(969)**	**(1,034)**	**137**	**(897)**
Other long-term liabilities							
Foreign exchange contracts	**—**	**(11)**	**—**	**(1,420)**	**(1,431)**	**29**	**(1,402)**
Interest rate contracts	**(6)**	**—**	**(3)**	**—**	**(9)**	**1**	**(8)**
Commodity contracts	**—**	**—**	**—**	**(153)**	**(153)**	**25**	**(128)**
Other contracts	**(3)**	**—**	**—**	**(4)**	**(7)**	**—**	**(7)**
	(9)	**(11)**	**(3)**	**(1,577)**	**(1,600)**	**55**	**(1,545)**
Total net derivative asset/(liability)							
Foreign exchange contracts	**(1)**	**(10)**	**—**	**(1,686)**	**(1,697)**	**—**	**(1,697)**
Interest rate contracts	**35**	**—**	**(12)**	**(179)**	**(156)**	**—**	**(156)**
Commodity contracts	**19**	**—**	**—**	**(433)**	**(414)**	**—**	**(414)**
Other contracts	**(4)**	**—**	**—**	**(12)**	**(16)**	**—**	**(16)**
	49	**(10)**	**(12)**	**(2,310)**	**(2,283)**	**—**	**(2,283)**

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.

September 30, 2018	2018	2019	2020	2021	2022	Thereafter[1]
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**591**	**3**	**1**	**—**	**—**	**—**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**1,592**	**3,262**	**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)*	**42**	**208**	**—**	**—**	**—**	**—**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**—**	**—**	**23**	**94**	**94**	**698**
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)*	**1,251**	**3,590**	**1,093**	**121**	**93**	**203**
Interest rate contracts - long-term receive fixed rate *(millions of Canadian dollars)*	**145**	**582**	**555**	**188**	**102**	**—**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**1,894**	**600**	**573**	**—**	**—**	**—**
Equity contracts *(millions of Canadian dollars)*	**40**	**35**	**20**	**—**	**—**	**—**
Commodity contracts - natural gas *(billions of cubic feet)*	**(7)**	**(58)**	**(18)**	**(5)**	**8**	**1**
Commodity contracts - crude oil *(millions of barrels)*	**4**	**4**	**—**	**—**	**—**	**—**
Commodity contracts - NGL *(millions of barrels)*	**(1)**	**—**	**—**	**—**	**—**	**—**
Commodity contracts - power *(megawatt per hour) (MW/H))*	**57**	**64**	**66**	**(3)**	**(43)**	**(43)**

1 As at September 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 September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(16)**	(2)	**2**	(1)
Interest rate contracts	**69**	83	**186**	28
Commodity contracts	**4**	—	**1**	12
Other contracts	**(10)**	16	**(12)**	1
Net investment hedges				
Foreign exchange contracts	**25**	148	**36**	221
	72	245	**213**	261
Amount of (gain)/loss reclassified from AOCI to earnings *(effective portion)*				
Foreign exchange contracts[1]	**7**	(3)	**4**	(104)
Interest rate contracts[2]	**40**	50	**124**	134
Commodity contracts[3]	**—**	—	**(1)**	(4)
Other contracts[4]	**7**	(11)	**10**	2
	54	36	**137**	28
Amount of (gain)/loss reclassified from AOCI to earnings *(ineffective portion and amount excluded from effectiveness testing)*				
Interest rate contracts[2]	**(2)**	(1)	**8**	5
	(2)	(1)	**8**	5

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 $1 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 27 months as at September 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. The difference in the amounts, if any, represents hedge ineffectiveness.

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Unrealized gain/(loss) on derivative	**3**	—	**(9)**	(1)
Unrealized gain/(loss) on hedged item	**(3)**	1	**8**	2
Realized gain/(loss) on derivative	**(3)**	2	**(4)**	2
Realized gain/(loss) on hedged item	**3**	(2)	**4**	(2)

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 September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**345**	503	**(356)**	1,210
Interest rate contracts[2]	**6**	(1)	**4**	13
Commodity contracts[3]	**(113)**	(160)	**43**	22
Other contracts[4]	**(8)**	3	**(10)**	(2)
Total unrealized derivative fair value gain/(loss), net	**230**	345	**(319)**	1,243

1 For the respective nine months ended periods, reported within Transportation and other services revenues (2018 - $346 million loss; 2017 - $726 million gain) and Other income/(expense) (2018 - $10 million loss; 2017 - $484 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 nine months ended periods, reported within Transportation and other services revenues (2018 - $16 million loss; 2017 - $85 million loss), Commodity sales (2018 - $42 million loss; 2017 - $67 million gain), Commodity costs (2018 - $90 million gain; 2017 - $22 million gain) and Operating and administrative expense (2018 - $11 million gain; 2017 - $18 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 September 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:

	September 30, 2018	December 31, 2017
(millions of Canadian dollars)		
Canadian financial institutions	**28**	82
United States financial institutions	**44**	19
European financial institutions	**79**	145
Asian financial institutions	**31**	2
Other[1]	**86**	137
	268	385

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

As at September 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 September 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:

September 30, 2018	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**67**	**—**	**67**
Interest rate contracts	**—**	**49**	**—**	**49**
Commodity contracts	**1**	**9**	**110**	**120**
	1	**125**	**110**	**236**
Long-term derivative assets				
Foreign exchange contracts	**—**	**43**	**—**	**43**
Interest rate contracts	**—**	**42**	**—**	**42**
Commodity contracts	**—**	**5**	**25**	**30**
Other contracts	**—**	**—**	**—**	**—**
	—	**90**	**25**	**115**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(376)**	**—**	**(376)**
Interest rate contracts	**—**	**(238)**	**—**	**(238)**
Commodity contracts	**(11)**	**(37)**	**(363)**	**(411)**
Other contracts	**—**	**(9)**	**—**	**(9)**
	(11)	**(660)**	**(363)**	**(1,034)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,431)**	**—**	**(1,431)**
Interest rate contracts	**—**	**(9)**	**—**	**(9)**
Commodity contracts	**—**	**(11)**	**(142)**	**(153)**
Other contracts	**—**	**(7)**	**—**	**(7)**
	—	**(1,458)**	**(142)**	**(1,600)**
Total net financial liabilities				
Foreign exchange contracts	**—**	**(1,697)**	**—**	**(1,697)**
Interest rate contracts	**—**	**(156)**	**—**	**(156)**
Commodity contracts	**(10)**	**(34)**	**(370)**	**(414)**
Other contracts	**—**	**(16)**	**—**	**(16)**
	(10)	**(1,903)**	**(370)**	**(2,283)**

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:

September 30, 2018	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(6)**	**Forward gas price**	**2.34**	**4.93**	**3.36**	**$/mmbtu[2]**
Crude	**(38)**	**Forward crude price**	**51.62**	**178.33**	**76.45**	**$/barrel**
NGL	**(2)**	**Forward NGL price**	**1.39**	**1.67**	**1.58**	**$/gallon**
Power	**(93)**	**Forward power price**	**26.01**	**72.42**	**47.74**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(83)**	**Forward gas price**	**1.08**	**6.24**	**2.75**	**$/mmbtu[2]**
Crude	**(141)**	**Forward crude price**	**29.79**	**123.22**	**81.29**	**$/barrel**
NGL	**(7)**	**Forward NGL price**	**0.71**	**2.16**	**1.13**	**$/gallon**
	(370)					

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:

	Nine months ended September 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]	**(146)**	1
Included in OCI	**—**	11
Settlements	**163**	83
Level 3 net derivative liability at end of period	**(370)**	(200)

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 September 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 $100 million and $99 million as at September 30, 2018 and December 31, 2017, respectively.

We have Restricted long-term investments held in trust totaling $307 million and $267 million as at September 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 $370 million and $371 million as at September 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 September 30, 2018 and December 31, 2017, the fair value of this preferred share investment approximates its face value of $580 million.

As at September 30, 2018 and December 31, 2017, our long-term debt had a carrying value of $62.5 billion and $64.0 billion, respectively, before debt issuance costs and a fair value of $63.8 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 September 30, 2018 and December 31, 2017, the noncurrent notes receivable has a carrying value of $92 million and $89 million, respectively, and a fair value of $92 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 nine months ended September 30, 2018 and 2017, we recognized an unrealized foreign exchange loss of $209 million and a gain of $350 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 $36 million and $222 million, respectively, in OCI. During the nine months ended September 30, 2018 and 2017, we recognized realized losses of $46 million and $128 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and recognized a realized loss of $13 million and a realized gain of $52 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 nine months ended September 30, 2018 and 2017.

12. INCOME TAXES

The effective income tax rates for the three months ended September 30, 2018 and 2017 were an expense of 62.0% and 24.4%, respectively, and for the nine months ended September 30, 2018 and 2017 were an expense of 7.9% and 20.4%, respectively. The period-over-period change in the effective income tax rate is due to the effects of rate-regulated accounting for income taxes, the goodwill impairment recorded in the third quarter of 2018, and other permanent items relative to the decrease in earnings for the three and nine months ended September 30, 2018, the impact of the United States federal corporate income tax rate reduction enacted in 2017, and a recovery in the second quarter of 2018 related to a change in assertion for the investment in Canadian renewable assets due to the sale which resulted in the recognition of previously unrecognized tax basis. Refer to *Note 6. Acquisitions and Dispositions - Dispositions - Renewable 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 nine months ended September 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 September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(millions of Canadian dollars)				
Service cost	**46**	65	**162**	181
Interest cost	**39**	46	**126**	125
Expected return on plan assets	**(72)**	(71)	**(234)**	(195)
Amortization of actuarial loss	**6**	11	**21**	28
Plan curtailments	**—**	—	**2**	—
Amortization of prior service costs	**—**	(1)	**(1)**	(1)
Net periodic benefit costs	**19**	50	**76**	138

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.

SIMPLIFICATION OF CORPORATE STRUCTURE

During the third quarter of 2018, we entered into definitive agreements with SEP, EEP, EEM and Enbridge Income Fund Holdings Inc. (ENF) under which we will acquire all of the outstanding public securities of the respective sponsored vehicles. The security holders of SEP, EEP, EEM and ENF will be entitled to receive 1.111, 0.335, 0.335 and 0.735 of our common shares for each of their own outstanding public securities, respectively. In addition, ENF shareholders will also receive cash payment of no less than $0.45 for each outstanding public common share of ENF, which amounts to approximately $63 million in the minimum. Closing of the transactions is subject to security holder approvals, customary closing conditions and other conditions, as applicable to the specific sponsored vehicle.

15. SUBSEQUENT EVENTS

On October 1, 2018, we closed the sale of the provincially regulated facilities of our Canadian natural gas gathering and processing businesses for proceeds of approximately $2.5 billion. Refer to *Note 6. Acquisitions and Dispositions* for further discussion of the transaction.

The BC Pipeline T-South System moves natural gas into the Pacific Northwest region and is comprised of two pipelines that run parallel to each other. On October 9, 2018, a rupture occurred on one of the natural gas transmission pipelines within this system and ignited at the site. Both pipelines were shut down following the rupture. Following various assessments and National Energy Board approval, both of the pipelines were returned to service at a lower operating pressure. We are cooperating and working with the Transportation Safety Board in its investigation to determine the cause of the incident.