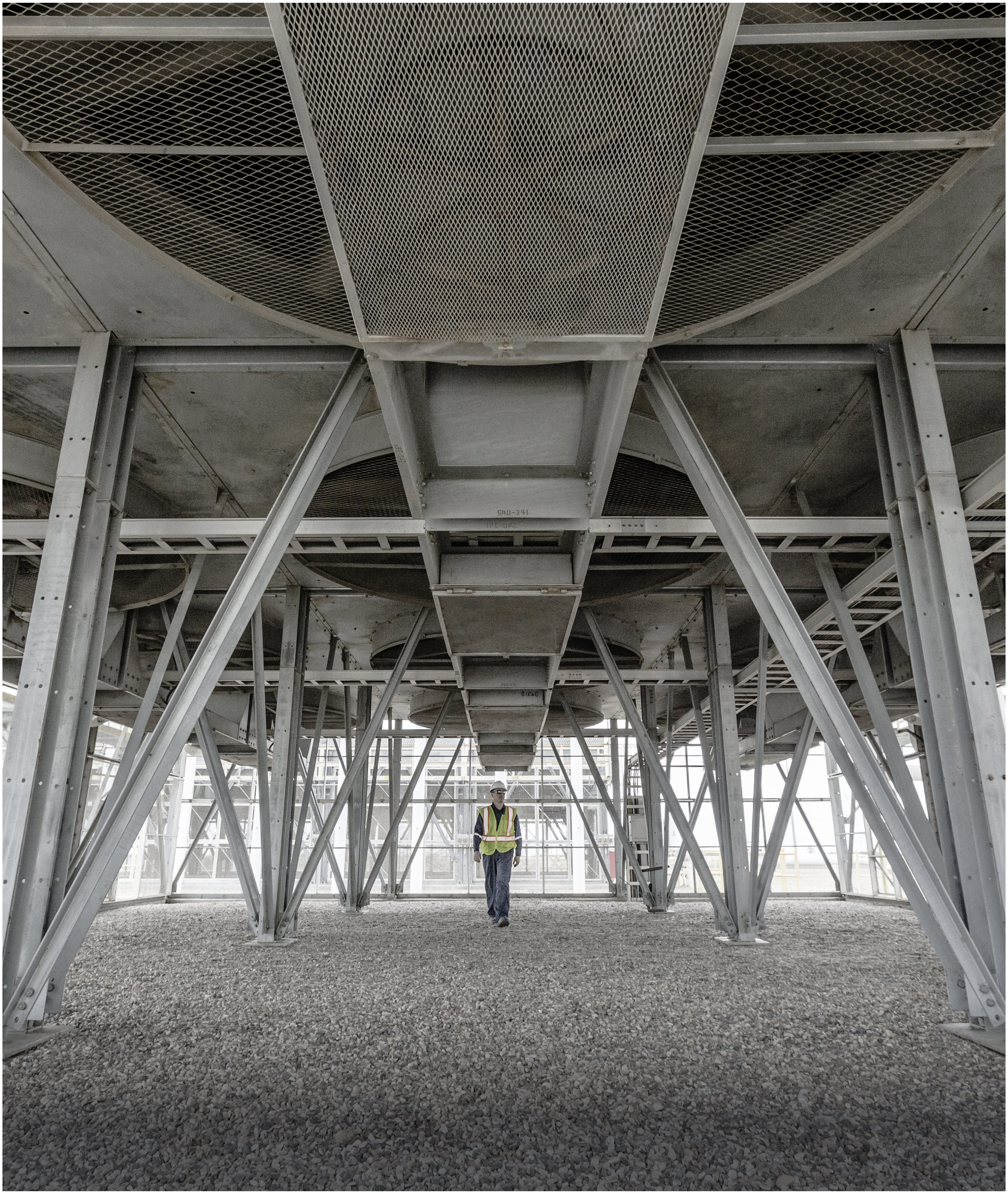
ENBRIDGE
Life Takes Energy

Second Quarter

Interim Report to Shareholders
For the six months ended June 30, 2019



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

FORM 10-Q

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

For the quarterly period ended June 30, 2019

OR

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

For the transition period from to

Commission file number 1-10934

ENBRIDGE INC

(Exact Name of Registrant as Specified in Its Charter)

Canada	**98-0377957**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

200, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
(Address of Principal Executive Offices) (Zip Code)

(403) 231-3900
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Shares	ENB	New York Stock Exchange
6.375% Fixed-to-Floating Rate Subordinated Notes Series 2018-B due 2078	ENBA	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

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

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

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

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

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

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

The registrant had 2,023,832,187 common shares outstanding as at July 26, 2019.

GLOSSARY

AOCI	Accumulated other comprehensive income/(loss)
Army Corps	United States Army Corps of Engineers
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
EBITDA	Earnings before interest, income taxes and depreciation and amortization
EEP	Enbridge Energy Partners, L.P.
Enbridge	Enbridge Inc.
Merger Transaction	Combination of Enbridge and Spectra Energy through a stock-for-stock merger transaction which closed on February 27, 2017
MNPUC	Minnesota Public Utilities Commission
MOLP	Midcoast Operating, L.P. and its subsidiaries
NGL	Natural gas liquids
OCI	Other comprehensive income/(loss)
SEP	Spectra Energy Partners, LP
VIE	Variable Interest Entity

CONVENTIONS

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

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

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this *quarterly report on Form 10-Q* to provide information about us and our subsidiaries and affiliates, including management’s assessment of our and our subsidiaries’ future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as ‘‘anticipate”, “believe”, “estimate”, “expect”, “forecast”, “intend”, “likely”, “plan”, “project”, “target” and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows; expected performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution, Renewable Power Generation and Transmission, and Energy Services businesses; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners’ ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and expected timing thereof; estimated future dividends; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; expectations regarding the impact of the stock-for-stock merger transaction completed on February 27, 2017 between Enbridge and Spectra Energy Corp (the Merger Transaction) including our combined scale, financial flexibility, growth program, future business prospects and performance; United States Line 3 Replacement Program (U.S. L3R Program); expected impact of the Federal Energy Regulatory Commission (FERC) policy on treatment of income taxes; the transactions undertaken to simplify our corporate structure; our dividend payout policy; dividend growth and dividend payout expectation; expectations on impact of our hedging program; and expectations resulting from the successful execution of our 2018-2020 Strategic Plan.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of dispositions; the realization of anticipated benefits and synergies of the Merger Transaction; governmental legislation; acquisitions and the timing thereof; the success of integration plans; impact of the dividend policy on our future cash flows; credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with *respect to the impact of the Merger Transaction on us, expected EBITDA, expected earnings/(loss), expected earnings/(loss) per share, or estimated future dividends. The most relevant assumptions associated with forward-looking statements regarding announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government and regulatory approvals on construction and in-service schedules and cost recovery regimes.*

Our forward-looking statements are subject to risks and uncertainties pertaining to the realization of anticipated benefits and synergies of the Merger Transaction, operating performance, regulatory parameters, changes in regulations applicable to our business, dispositions, the transactions undertaken to simplify our corporate structure, our dividend policy, project approval and support, renewals of rights-of-way, weather, economic and competitive conditions, public opinion, changes in tax laws and tax rates, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this quarterly report on Form 10-Q and in our other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge Inc. assumes no obligation to publicly update or revise any forward-looking statements made in this quarterly report on Form 10-Q or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

PART I - FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(unaudited; millions of Canadian dollars, except per share amounts)				
Operating revenues				
Commodity sales	**8,416**	6,451	**15,048**	13,719
Gas distribution sales	**755**	856	**2,631**	2,782
Transportation and other services	**4,092**	3,438	**8,440**	6,970
Total operating revenues *(Note 3)*	**13,263**	10,745	**26,119**	23,471
Operating expenses				
Commodity costs	**8,129**	6,278	**14,694**	13,275
Gas distribution costs	**312**	421	**1,519**	1,745
Operating and administrative	**1,695**	1,636	**3,320**	3,277
Depreciation and amortization	**842**	829	**1,682**	1,653
Impairment of long-lived assets	**—**	10	**—**	1,072
Total operating expenses	**10,978**	9,174	**21,215**	21,022
Operating income	**2,285**	1,571	**4,904**	2,449
Income from equity investments	**413**	363	**826**	698
Other income/(expense)				
Net foreign currency gain/(loss)	**140**	(43)	**354**	(228)
Other	**65**	29	**111**	94
Interest expense	**(637)**	(690)	**(1,322)**	(1,346)
Earnings before income taxes	**2,266**	1,230	**4,873**	1,667
Income tax (expense)/recovery *(Note 12)*	**(436)**	97	**(1,020)**	170
Earnings	**1,830**	1,327	**3,853**	1,837
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**2**	(167)	**(35)**	(143)
Earnings attributable to controlling interests	**1,832**	1,160	**3,818**	1,694
Preference share dividends	**(96)**	(89)	**(191)**	(178)
Earnings attributable to common shareholders	**1,736**	1,071	**3,627**	1,516
Earnings per common share attributable to common shareholders *(Note 5)*	**0.86**	0.63	**1.80**	0.90
Diluted earnings per common share attributable to common shareholders *(Note 5)*	**0.86**	0.63	**1.80**	0.90

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(unaudited; millions of Canadian dollars)				
Earnings	**1,830**	1,327	**3,853**	1,837
Other comprehensive income/(loss), net of tax				
Change in unrealized gain/(loss) on cash flow hedges	**(235)**	27	**(427)**	93
Change in unrealized gain/(loss) on net investment hedges	**127**	(99)	**221**	(283)
Other comprehensive income from equity investees	**5**	5	**17**	19
Reclassification to earnings of loss on cash flow hedges	**35**	36	**46**	73
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**5**	62	**43**	23
Foreign currency translation adjustments	**(1,311)**	1,047	**(2,602)**	2,626
Other comprehensive income/(loss), net of tax	**(1,374)**	1,078	**(2,702)**	2,551
Comprehensive income	**456**	2,405	**1,151**	4,388
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**51**	(297)	**64**	(444)
Comprehensive income attributable to controlling interests	**507**	2,108	**1,215**	3,944
Preference share dividends	**(96)**	(89)	**(191)**	(178)
Comprehensive income attributable to common shareholders	**411**	2,019	**1,024**	3,766

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(unaudited; millions of Canadian dollars, except per share amounts)				
Preference shares *(Note 5)*				
Balance at beginning and end of period	**7,747**	7,747	**7,747**	7,747
Common shares *(Note 5)*				
Balance at beginning of period	**64,728**	51,127	**64,677**	50,737
Dividend Reinvestment and Share Purchase Plan	**—**	416	**—**	790
Shares issued on exercise of stock options	**4**	5	**55**	21
Balance at end of period	**64,732**	51,548	**64,732**	51,548
Additional paid-in capital				
Balance at beginning of period	**72**	4,313	**—**	3,194
Stock-based compensation	**17**	17	**21**	34
Options exercised	**(6)**	(4)	**(49)**	(10)
Dilution gain on Spectra Energy Partners, LP restructuring	**—**	—	**—**	1,136
Change in reciprocal interest	**—**	—	**109**	—
Repurchase of noncontrolling interest	**65**	—	**65**	—
Other	**46**	(15)	**48**	(43)
Balance at end of period	**194**	4,311	**194**	4,311
Deficit				
Balance at beginning of period	**(3,640)**	(1,982)	**(5,538)**	(2,468)
Earnings attributable to controlling interests	**1,832**	1,160	**3,818**	1,694
Preference share dividends	**(96)**	(89)	**(191)**	(178)
Dividends paid to reciprocal shareholder	**4**	10	**9**	17
Common share dividends declared	**(1,500)**	(1,145)	**(1,500)**	(1,145)
Modified retrospective adoption of *ASC 606 Revenue from Contracts with Customers*	**—**	—	**—**	(86)
Redemption value adjustment attributable to redeemable noncontrolling interests	**—**	(603)	**—**	(483)
Other	**8**	—	**10**	—
Balance at end of period	**(3,392)**	(2,649)	**(3,392)**	(2,649)
Accumulated other comprehensive income/(loss) *(Note 9)*				
Balance at beginning of period	**1,449**	329	**2,672**	(973)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**(1,325)**	948	**(2,603)**	2,250
Other	**—**	—	**55**	—
Balance at end of period	**124**	1,277	**124**	1,277
Reciprocal shareholding				
Balance at beginning of period	**(51)**	(102)	**(88)**	(102)
Change in reciprocal interest	**—**	—	**37**	—
Balance at end of period	**(51)**	(102)	**(51)**	(102)
Total Enbridge Inc. shareholders' equity	**69,354**	62,132	**69,354**	62,132
Noncontrolling interests				
Balance at beginning of period	**3,614**	6,082	**3,965**	7,597
Earnings/(loss) attributable to noncontrolling interests	**(2)**	106	**35**	129
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax				
Change in unrealized gain/(loss) on cash flow hedges	**(4)**	2	**(5)**	6
Foreign currency translation adjustments	**(45)**	77	**(94)**	229
Reclassification to earnings of loss on cash flow hedges	**—**	7	**—**	15
	(49)	86	**(99)**	250
Comprehensive income/(loss) attributable to noncontrolling interests	**(51)**	192	**(64)**	379
Spectra Energy Partners, LP restructuring	**—**	—	**—**	(1,486)
Contributions	**6**	13	**9**	21
Distributions	**(54)**	(216)	**(100)**	(425)
Repurchase of noncontrolling interest	**(65)**	—	**(65)**	—
Redemption of preferred shares held by subsidiary *(Note 10)*	**—**	—	**(300)**	—
Other	**1**	29	**6**	14
Balance at end of period	**3,451**	6,100	**3,451**	6,100
Total equity	**72,805**	68,232	**72,805**	68,232
Dividends paid per common share	**0.738**	0.671	**1.476**	1.342
Earnings per common share attributable to common shareholders *(Note 5)*	**0.86**	0.63	**1.80**	0.90
Diluted earnings per common share attributable to common shareholders *(Note 5)*	**0.86**	0.63	**1.80**	0.90

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six months ended June 30,	
	2019	2018
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**3,853**	1,837
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**1,682**	1,653
Deferred income tax (recovery)/expense	**809**	(328)
Changes in unrealized (gain)/loss on derivative instruments, net *(Note 11)*	**(1,112)**	549
Earnings from equity investments	**(826)**	(698)
Distributions from equity investments	**907**	732
Impairment of long-lived assets	**—**	1,072
Loss on dispositions	**—**	11
Other	**36**	110
Changes in operating assets and liabilities	**(679)**	1,600
Net cash provided by operating activities	**4,670**	6,538
Investing activities		
Capital expenditures	**(2,785)**	(3,243)
Long-term investments and restricted long-term investments	**(700)**	(611)
Distributions from equity investments in excess of cumulative earnings	**268**	1,140
Additions to intangible assets	**(100)**	(425)
Proceeds from dispositions	**—**	4
Other	**—**	(4)
Affiliate loans, net	**(140)**	—
Net cash used in investing activities	**(3,457)**	(3,139)
Financing activities		
Net change in short-term borrowings	**(108)**	(433)
Net change in commercial paper and credit facility draws	**4,015**	(2,166)
Debenture and term note issues, net of issue costs	**1,195**	3,537
Debenture and term note repayments	**(2,584)**	(2,147)
Contributions from noncontrolling interests	**9**	21
Distributions to noncontrolling interests	**(100)**	(425)
Contributions from redeemable noncontrolling interests	**—**	41
Distributions to redeemable noncontrolling interests	**—**	(174)
Common shares issued	**18**	14
Preference share dividends	**(191)**	(174)
Common share dividends	**(2,976)**	(1,493)
Redemption of preferred shares held by subsidiary *(Note 10)*	**(300)**	—
Other	**(36)**	—
Net cash used in financing activities	**(1,058)**	(3,399)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(25)**	35
Net increase in cash and cash equivalents and restricted cash	**130**	35
Cash and cash equivalents and restricted cash at beginning of period	**637**	587
Cash and cash equivalents and restricted cash at end of period	**767**	622

See accompanying notes to the interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2019	December 31, 2018
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**708**	518
Restricted cash	**59**	119
Accounts receivable and other	**6,257**	6,517
Accounts receivable from affiliates	**85**	79
Inventory	**1,284**	1,339
	8,393	8,572
Property, plant and equipment, net	**93,202**	94,540
Long-term investments	**16,531**	16,707
Restricted long-term investments	**389**	323
Deferred amounts and other assets	**9,552**	8,558
Intangible assets, net	**2,215**	2,372
Goodwill	**33,342**	34,459
Deferred income taxes	**1,204**	1,374
Total assets	**164,828**	166,905
Liabilities and equity		
Current liabilities		
Short-term borrowings	**916**	1,024
Accounts payable and other	**7,156**	9,863
Accounts payable to affiliates	**26**	40
Interest payable	**626**	669
Current portion of long-term debt	**4,644**	3,259
	13,368	14,855
Long-term debt	**60,017**	60,327
Other long-term liabilities	**8,871**	8,834
Deferred income taxes	**9,767**	9,454
	92,023	93,470
Contingencies *(Note 15)*		
Equity		
Share capital		
Preference shares	**7,747**	7,747
Common shares *(2,024 and 2,022 outstanding at June 30, 2019 and December 31, 2018, respectively)*	**64,732**	64,677
Additional paid-in capital	**194**	—
Deficit	**(3,392)**	(5,538)
Accumulated other comprehensive income *(Note 9)*	**124**	2,672
Reciprocal shareholding	**(51)**	(88)
Total Enbridge Inc. shareholders' equity	**69,354**	69,470
Noncontrolling interests	**3,451**	3,965
	72,805	73,435
Total liabilities and equity	**164,828**	166,905

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 updated consolidated financial statements and notes for the year ended December 31, 2018. 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 audited updated consolidated financial statements for the year ended December 31, 2018, 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.

2. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW STANDARDS

Cloud Computing Arrangements

Effective January 1, 2019, we adopted Accounting Standards Update (ASU) 2018-15 on a prospective basis. The new standard was issued to provide guidance on the accounting for implementation costs incurred in a cloud computing arrangement that is a service contract. The ASU specifies that an entity would apply Accounting Standards Codification (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. The amendments in the update also require that the 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, in addition to specifying that the capitalized costs must be presented on the same balance sheet line as the prepayment of fees related to the hosting arrangement. The ASU requires similar consistency in classifications from a cash flow statement perspective. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Improvements to Accounting for Hedging Activities

Effective January 1, 2019, we adopted ASU 2017-12 on a modified retrospective basis. The new standard was issued 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. As a result of the new standard, hedge ineffectiveness will no longer be measured or recorded, and hedging instruments’ fair value changes will be recorded in the same income statement line as the hedged item. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

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

Effective January 1, 2019, we adopted ASU 2017-08 on a modified retrospective basis. The new standard was issued with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The adoption of this accounting update did not have a material impact on our consolidated financial statements.

Recognition of Leases

Effective January 1, 2019 we adopted ASU 2016-02 Leases (Topic 842) using the modified retrospective approach.

We recognize an arrangement 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 recognize right-of-use (ROU) assets and the related lease liabilities on the statement of financial position for operating lease arrangements with a term of 12 months or longer. We do not separate non-lease components from the associated lease components of our lessee contracts and account for both components as a single lease component. We combine lease and non-lease components within a contract for operating lessor leases when certain conditions are met. ROU assets are assessed for impairment using the same approach as is applied for other long-lived assets, as described under the Impairment section of the Significant Accounting Policies Note 2 in the annual consolidated financial statements.

Lease liabilities and ROU assets require the use of judgment and estimates, which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, whether there are any indicators of impairment for ROU assets and whether any ROU assets should be grouped with other long-lived assets for impairment testing.

In adopting Topic 842, we elected the package of practical expedients permitted under the transition guidance. 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. The application of the package of practical expedients also permits entities not to reassess whether any expired or existing contracts contain leases in accordance with the new guidance, lease classifications, and whether initial direct costs capitalized under current guidance continue to meet the definition of initial direct costs under the new guidance. We also elected the practical expedient related to land easements, allowing us to carry forward our accounting treatment for land easements on existing agreements that had commenced prior to January 1, 2019.

On January 1, 2019, ROU assets and corresponding lease liabilities of $771 million were recorded in connection with the adoption of Topic 842. When added to the $85 million of pre-existing liabilities relating to operating leases for which we no longer utilize the leased assets, total lease liabilities at January 1, 2019 were $856 million. All lease liabilities were measured using a weighted average discount rate of 4.32%. The adoption of this standard had no impact to the Consolidated Statements of Earnings, Comprehensive Income, Changes in Equity or Cash Flows during the period.

FUTURE ACCOUNTING POLICY CHANGES

Clarifying Interaction between Collaborative Arrangements and Revenue from Contracts with Customers

In November 2018, ASU 2018-18 was issued to provide clarity on when transactions between entities in a collaborative arrangement should be accounted for under the new revenue standard, ASC 606. In determining whether transactions in collaborative arrangements should be accounted under the revenue standard, the update specifies that entities shall apply unit of account guidance to identify distinct goods or services and whether such goods and services are separately identifiable from other promises in the contract. ASU 2018-18 also precludes entities from presenting transactions with a collaborative partner which are not in scope of the new revenue standard together with revenue from contracts with customers. The accounting update 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.

Improvements to Related Party Guidance for Variable Interest Entities

ASU 2018-17 was issued in October 2018 to improve the related party guidance on determining whether fees paid to decision makers and service providers (decision maker fees) are variable interests. Under the new guidance, reporting entities must consider indirect interests held through related parties in common control arrangements on a proportionate basis, rather than as the equivalent of a direct interest in its entirety, when determining if decision maker fees constitute a variable interest. The accounting update is effective January 1, 2020 and must be applied on a retrospective basis. 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.

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 delay 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.

Further, ASU 2018-19 was issued in November 2018 to clarify that operating lease receivables should be accounted for under the new leases standard, ASC 842, and are not within the scope of ASC 326, Financial Instruments - Credit Losses. Both accounting updates are effective January 1, 2020. We are currently assessing the impact of the new standard on our consolidated financial statements.

3. REVENUES

Effective January 1, 2019, we renamed the Green Power and Transmission segment to Renewable Power Generation and Transmission. The presentation of the prior years' tables has been revised in order to align with the current presentation.

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Three months ended June 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	**2,230**	**1,113**	**171**	**—**	**—**	**—**	**3,514**
Storage and other revenues	**25**	**46**	**52**	**—**	**—**	**—**	**123**
Gas gathering and processing revenues	**—**	**115**	**—**	**—**	**—**	**—**	**115**
Gas distribution revenue	**—**	**—**	**754**	**—**	**—**	**—**	**754**
Electricity and transmission revenues	**—**	**—**	**—**	**43**	**—**	**—**	**43**
Commodity sales	**—**	**3**	**—**	**—**	**—**	**—**	**3**
Total revenue from contracts with customers	**2,255**	**1,277**	**977**	**43**	**—**	**—**	**4,552**
Commodity sales	**—**	**—**	**—**	**—**	**8,413**	**—**	**8,413**
Other revenues[1,2]	**199**	**10**	**(3)**	**94**	**(7)**	**5**	**298**
Intersegment revenues	**115**	**1**	**3**	**—**	**12**	**(131)**	**—**
Total revenues	**2,569**	**1,288**	**977**	**137**	**8,418**	**(126)**	**13,263**

Three months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	2,079	958	151	—	—	—	3,188
Storage and other revenues	42	51	52	—	—	—	145
Gas gathering and processing revenues	—	231	—	—	—	—	231
Gas distribution revenues	—	—	856	—	—	—	856
Electricity and transmission revenues	—	—	—	53	—	—	53
Commodity sales	—	639	—	—	—	—	639
Total revenue from contracts with customers	2,121	1,879	1,059	53	—	—	5,112
Commodity sales	—	—	—	—	5,812	—	5,812
Other revenues[1, 2]	(261)	(17)	9	96	—	(6)	(179)
Intersegment revenues	90	2	2	—	24	(118)	—
Total revenues	1,950	1,864	1,070	149	5,836	(124)	10,745

Six months ended June 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	**4,444**	**2,250**	**420**	**—**	**—**	**—**	**7,114**
Storage and other revenues	**52**	**99**	**106**	**—**	**—**	**—**	**257**
Gas gathering and processing revenues	**—**	**231**	**—**	**—**	**—**	**—**	**231**
Gas distribution revenue	**—**	**—**	**2,610**	**—**	**—**	**—**	**2,610**
Electricity and transmission revenues	**—**	**—**	**—**	**93**	**—**	**—**	**93**
Commodity sales	**—**	**3**	**—**	**—**	**—**	**—**	**3**
Total revenue from contracts with customers	**4,496**	**2,583**	**3,136**	**93**	**—**	**—**	**10,308**
Commodity sales	**—**	**—**	**—**	**—**	**15,045**	**—**	**15,045**
Other revenues[1,2]	**539**	**20**	**26**	**196**	**(1)**	**(14)**	**766**
Intersegment revenues	**192**	**3**	**6**	**—**	**47**	**(248)**	**—**
Total revenues	**5,227**	**2,606**	**3,168**	**289**	**15,091**	**(262)**	**26,119**

Six months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenues	4,137	1,910	390	—	—	—	6,437
Storage and other revenues	82	111	118	—	—	—	311
Gas gathering and processing revenues	—	436	—	—	—	—	436
Gas distribution revenues	—	—	2,782	—	—	—	2,782
Electricity and transmission revenues	—	—	—	110	—	—	110
Commodity sales	—	1,332	—	—	—	—	1,332
Total revenue from contracts with customers	4,219	3,789	3,290	110	—	—	11,408
Commodity sales	—	—	—	—	12,387	—	12,387
Other revenues[1, 2]	(530)	8	11	196	—	(9)	(324)
Intersegment revenues	170	4	6	—	81	(261)	—
Total revenues	3,859	3,801	3,307	306	12,468	(270)	23,471

1 *Includes mark-to-market gains/(losses) from our hedging program.*
2 *Includes revenues from lease contracts. Refer to Note 14 Leases.*

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

Contract Balances

	Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at December 31, 2018	**1,929**	**191**	**1,297**
Balance as at June 30, 2019	**1,845**	**191**	**1,275**

Contract receivables represent the amount of receivables derived from contracts with customers. Contract assets represent the amount of revenues 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 revenues. Revenue recognized during the three and six months ended June 30, 2019 included in contract liabilities at the beginning of the period was $38 million and $130 million, respectively. Increases in contract liabilities from cash received, net of amounts recognized as revenues during the three and six months ended June 30, 2019 were $69 million and $143 million, respectively.

Performance Obligations

There were no material revenues recognized in the three and six months ended June 30, 2019 from performance obligations satisfied in previous periods.

Revenues to be Recognized from Unfulfilled Performance Obligations

Total revenues from performance obligations expected to be fulfilled in future periods is $65.2 billion, of which $3.6 billion and $6.0 billion is expected to be recognized during the six months ending December 31, 2019, and the year ending December 31, 2020, 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 revenue 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 revenues 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, revenue from contracts with customers which have an original expected duration of one year or less are excluded from the amounts above.

Recognition and Measurement of Revenues

Three months ended June 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	**—**	**3**	**17**	**—**	**—**	**20**
Revenues from products and services transferred over time[2]	**2,255**	**1,274**	**960**	**43**	**—**	**4,532**
Total revenue from contracts with customers	**2,255**	**1,277**	**977**	**43**	**—**	**4,552**

Three months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	—	639	20	—	—	659
Revenues from products and services transferred over time[2]	2,121	1,240	1,039	53	—	4,453
Total revenue from contracts with customers	2,121	1,879	1,059	53	—	5,112

Six months ended June 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	**—**	**3**	**34**	**—**	**—**	**37**
Revenues from products and services transferred over time[2]	**4,496**	**2,580**	**3,102**	**93**	**—**	**10,271**
Total revenue from contracts with customers	**4,496**	**2,583**	**3,136**	**93**	**—**	**10,308**

Six months ended June 30, 2018	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Consolidated
(millions of Canadian dollars)						
Revenues from products transferred at a point in time[1]	—	1,332	45	—	—	1,377
Revenues from products and services transferred over time[2]	4,219	2,457	3,245	110	—	10,031
Total revenue from contracts with customers	4,219	3,789	3,290	110	—	11,408

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

2 *Revenues 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.*

4. SEGMENTED INFORMATION

Three months ended June 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**2,569**	**1,288**	**977**	**137**	**8,418**	**(126)**	**13,263**
Commodity and gas distribution costs	**(7)**	**—**	**(344)**	**(1)**	**(8,209)**	**120**	**(8,441)**
Operating and administrative	**(776)**	**(563)**	**(268)**	**(40)**	**(1)**	**(47)**	**(1,695)**
Income from equity investments	**204**	**193**	**2**	**4**	**10**	**—**	**413**
Other income/(expense)	**2**	**23**	**23**	**(6)**	**3**	**160**	**205**
Earnings before interest, income taxes, and depreciation and amortization	**1,992**	**941**	**390**	**94**	**221**	**107**	**3,745**
Depreciation and amortization							**(842)**
Interest expense							**(637)**
Income tax expense							**(436)**
Earnings							**1,830**
Capital expenditures[1]	**522**	**424**	**223**	**2**	**1**	**14**	**1,186**

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

Six months ended June 30, 2019	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Renewable Power Generation and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**5,227**	**2,606**	**3,168**	**289**	**15,091**	**(262)**	**26,119**
Commodity and gas distribution costs	**(13)**	**—**	**(1,608)**	**(2)**	**(14,838)**	**248**	**(16,213)**
Operating and administrative	**(1,577)**	**(1,076)**	**(562)**	**(82)**	**(34)**	**11**	**(3,320)**
Income from equity investments	**401**	**390**	**13**	**18**	**3**	**1**	**826**
Other income/(expense)	**26**	**41**	**41**	**(5)**	**5**	**357**	**465**
Earnings before interest, income taxes, and depreciation and amortization	**4,064**	**1,961**	**1,052**	**218**	**227**	**355**	**7,877**
Depreciation and amortization							**(1,682)**
Interest expense							**(1,322)**
Income tax expense							**(1,020)**
Earnings							**3,853**
Capital expenditures[1]	**1,542**	**818**	**396**	**16**	**2**	**39**	**2,813**

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

1 Includes allowance for equity funds used during construction.

5. EARNINGS PER COMMON SHARE AND DIVIDENDS PER 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 6 million and 13 million for the three and six months ended June 30, 2019 and 2018, respectively, resulting from our reciprocal investment in Noverco Inc.

DILUTED

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

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

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(number of common shares in millions)				
Weighted average shares outstanding	**2,018**	1,695	**2,017**	1,690
Effect of dilutive options	**3**	3	**3**	3
Diluted weighted average shares outstanding	**2,021**	1,698	**2,020**	1,693

For the three months ended June 30, 2019 and 2018, 21.3 million and 30.2 million, respectively, anti-dilutive stock options with a weighted average exercise price of $53.33 and $49.67, respectively, were excluded from the diluted earnings per common share calculation.

For the six months ended June 30, 2019 and 2018, 15.9 million and 30.1 million, respectively, anti-dilutive stock options with a weighted average exercise price of $53.99 and $49.73, respectively, were excluded from the diluted earnings per common share calculation.

DIVIDENDS PER SHARE

On August 1, 2019, our Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2019, to shareholders of record on August 15, 2019.

	Dividend per share
Common Shares	$0.73800
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.21340
Preference Shares, Series C[1]	$0.25647
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series J	US$0.30540
Preference Shares, Series L	US$0.30993
Preference Shares, Series N	$0.31788
Preference Shares, Series P[2]	$0.27369
Preference Shares, Series R[3]	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3	$0.25000
Preference Shares, Series 5[4]	US$0.33596
Preference Shares, Series 7[5]	$0.27806
Preference Shares, Series 9	$0.27500
Preference Shares, Series 11	$0.27500
Preference Shares, Series 13	$0.27500
Preference Shares, Series 15	$0.27500
Preference Shares, Series 17	$0.32188
Preference Shares, Series 19	$0.30625

1 *The quarterly dividend per share paid on Series C was decreased to $0.25395 from $0.25459 on March 1, 2019 and was increased to $0.25647 from $0.25395 on June 1, 2019, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.*

2 *The quarterly dividend per share paid on Series P was increased to $0.27369 from $0.25000 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

3 *The quarterly dividend per share paid on Series R was increased to $0.25456 from $0.25000 on June 1, 2019, due to the reset of the annual dividend on June 1, 2019, and every five years thereafter.*

4 *The quarterly dividend per share paid on Series 5 was increased to US$0.33596 from US$0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

5 *The quarterly dividend per share paid on Series 7 was increased to $0.27806 from $0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.*

6. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

In January 2019, through our wholly-owned subsidiary Enbridge Pipelines (Athabasca) Inc., we acquired 75 kilometers of existing pipeline and tankage infrastructure (collectively, the Cheecham Assets) from Athabasca Oil Corporation for cash consideration of approximately $265 million, all of which was allocated to property, plant and equipment. The Cheecham Assets are a part of our Liquids Pipelines segment. The cash consideration is included in capital expenditures on our Consolidated Statements of Cash Flows for the six months ended June 30, 2019.

ASSETS HELD FOR SALE

Enbridge Gas New Brunswick

In December 2018, we entered into an agreement for the sale of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc. (collectively, EGNB) to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp., for a cash purchase price of $331 million, subject to customary closing adjustments. EGNB operates and maintains natural gas distribution pipelines in southern New Brunswick, and its related assets are included in our Gas Distribution segment. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in 2019.

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. On October 1, 2018, we closed the sale of the provincially regulated facilities for proceeds of approximately $2.5 billion. Subject to certain regulatory approvals and customary closing conditions, the sale of the federally regulated facilities is expected to close in 2019 for proceeds of approximately $1.8 billion.

Line 10 Crude Oil Pipeline

In the first quarter of 2018, we satisfied the conditions 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 wholly-owned subsidiaries, Enbridge Pipelines Inc. and Enbridge Energy Partners, L.P. (EEP), own the Canadian and United States portions of Line 10. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in 2019.

St. Lawrence Gas Company, Inc.

In August 2017, we entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas Company, Inc. Expected cash proceeds for the transaction are approximately $76 million (US$58 million). Subject to regulatory approval and certain pre-closing conditions, the transaction is expected to close in 2019.

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

	June 30, 2019	December 31, 2018
(millions of Canadian dollars)		
Accounts receivable and other (current assets held for sale)	**100**	117
Deferred amounts and other assets (long-term assets held for sale)[1]	**2,440**	2,383
Accounts payable and other (current liabilities held for sale)	**(48)**	(63)
Other long-term liabilities (long-term liabilities held for sale)	**(97)**	(96)
Net assets held for sale	**2,395**	2,341

1 Included within Deferred amounts and other assets at June 30, 2019 and December 31, 2018 respectively is property, plant and equipment of $2.2 billion and $2.1 billion.

7. VARIABLE INTEREST ENTITIES

Gray Oak Holdings LLC

In December 2018, Enbridge acquired an effective 22.8% interest in the Gray Oak crude oil pipeline through acquisition of a 35% membership interest in Gray Oak Holdings LLC (Gray Oak Holdings), which will construct and operate the Gray Oak crude oil pipeline from Texas to the Gulf coast of the United States.

Gray Oak Holdings is a variable interest entity (VIE) as it does not have sufficient equity at risk to finance its activities and requires subordinated financial support from Enbridge and other partners. We have determined that we do not have the power to direct the activities of Gray Oak Holdings that most significantly impact the VIE's economic performance. Specifically, the power to direct the activities of the VIE is shared amongst the partners. Each partner has representatives that make up an executive committee that makes the significant decisions for the VIE and none of the partners may make major decisions unilaterally. Therefore, the VIE is accounted for as an unconsolidated VIE.

As at June 30, 2019 and December 31, 2018, the carrying amount of the investment in Gray Oak Holdings was $455 million and nil, respectively. Enbridge's maximum exposure to loss as at June 30, 2019 was approximately $911 million and primarily consists of our portion of the project construction costs.

On June 4, 2019, the partners of Gray Oak executed a term loan facility with a syndicate of banks with a borrowing capacity of US$1,230 million to finance the construction of the Gray Oak crude oil pipeline. An Equity Contribution Agreement was executed by the partners of Gray Oak Holdings to backstop the term loan facility until certain release conditions are met. At June 30, 2019 Gray Oak had US$551 million outstanding, and the guarantee associated with our effective interest was US$125 million. On July 2, 2019, the partners exercised an option on the term loan facility for an additional US$87 million, bringing the total borrowing capacity under the facility to US$1,317 million. The maximum amount committed by Enbridge under the Equity Contribution Agreement is US$300 million, which is proportionate to our effective ownership interest.

8. DEBT

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, Spectra Energy Partners, LP (SEP) and EEP (together, the Partnerships), pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. See *Note 16 - Condensed Consolidating Financial Information* for further discussion.

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at June 30, 2019:

	Maturity	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2021-2024	**6,511**	**4,850**	**1,661**
Enbridge (U.S.) Inc.	2021-2024	**7,187**	**5,017**	**2,170**
Enbridge Pipelines Inc.	2020	**3,000**	**2,314**	**686**
Enbridge Gas Inc.	2019-2021	**2,017**	**926**	**1,091**
Total committed credit facilities		**18,715**	**13,107**	**5,608**

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

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, Enbridge Gas Inc. (EGI), EEP and SEP. We also increased existing facilities or obtained new facilities to replace the terminated ones under Enbridge, Enbridge (U.S.) Inc. and EGI. As a result, our total credit facility availability increased by approximately $444 million.

On May 16, 2019, Enbridge entered into a three year, extendible credit facility for $641 million (¥52.5 billion) with a syndicate of Japanese banks.

In addition to the committed credit facilities noted above, we maintain $887 million of uncommitted demand credit facilities, of which $571 million were unutilized as at June 30, 2019. As at December 31, 2018, we had $807 million of uncommitted credit facilities, of which $548 million were unutilized.

Our credit facilities carry a weighted average standby fee of 0.1% 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 2020 to 2024.

As at June 30, 2019 and December 31, 2018, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $12,181 million and $7,967 million, respectively, were supported by the availability of long-term committed credit facilities and therefore have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the six months ended June 30, 2019, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
(millions of Canadian dollars)			
Enbridge Pipelines Inc.			
	February 2019	3.52% medium-term notes due February 2029	$600
	February 2019	4.33% medium-term notes due February 2049	$600

LONG-TERM DEBT REPAYMENTS

During the six months ended June 30, 2019, we completed the following long-term debt repayments:

Company	Retirement/ Repayment Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.			
Repayment			
	February 2019	4.10% medium-term notes	$300
	May 2019	Floating rate notes	$750
Enbridge Energy Partners, L.P.			
Redemption			
	February 2019	8.05% fixed/floating rate junior subordinated notes due 2067	US$400
Repayment			
	March 2019	9.88% senior notes	US$500
Enbridge Pipelines (Southern Lights) L.L.C.			
Repayment			
	June 2019	3.98% medium-term notes due 2040	US$23
Westcoast Energy Inc.			
Repayment			
	January 2019	5.60% medium-term notes	$250
	January 2019	5.60% medium-term notes	$50
	May 2019	6.90% senior secured notes due 2019	$13
	May 2019	4.34% senior secured notes due 2019	$2

SUBORDINATED TERM NOTES

As at June 30, 2019 and December 31, 2018, our fixed-to-floating subordinated term notes had a principal value of $6,582 million and $7,317 million, respectively.

FAIR VALUE ADJUSTMENT

As at June 30, 2019, the net fair value adjustment for total debt assumed in the Merger Transaction was $898 million. During the three and six months ended June 30, 2019, the amortization of the fair value adjustment, recorded as a reduction to Interest expense in the Consolidated Statements of Earnings, was $17 million and $34 million, respectively.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at June 30, 2019, we were in compliance with all debt covenants.

9. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated Other Comprehensive Income (AOCI) attributable to our common shareholders for the six months ended June 30, 2019 and 2018 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, 2019	**(770)**	**(598)**	**4,323**	**34**	**(317)**	**2,672**
Other comprehensive income/(loss) retained in AOCI	**(618)**	**252**	**(2,508)**	**22**	**—**	**(2,852)**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**72**	**—**	**—**	**—**	**—**	**72**
Foreign exchange contracts[3]	**2**	**—**	**—**	**—**	**—**	**2**
Other contracts[4]	**(3)**	**—**	**—**	**—**	**—**	**(3)**
Amortization of pension and OPEB actuarial loss and prior service costs[5]	**—**	**—**	**—**	**—**	**57**	**57**
	(547)	**252**	**(2,508)**	**22**	**57**	**(2,724)**
Tax impact						
Income tax on amounts retained in AOCI	**196**	**(31)**	**—**	**(5)**	**—**	**160**
Income tax on amounts reclassified to earnings	**(25)**	**—**	**—**	**—**	**(14)**	**(39)**
	171	**(31)**	**—**	**(5)**	**(14)**	**121**
Other	**—**	**—**	**—**	**—**	**55**	**55**
Balance as at June 30, 2019	**(1,146)**	**(377)**	**1,815**	**51**	**(219)**	**124**

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

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

Preferred Shares Redemption
On March 20, 2019, Westcoast Energy Inc. exercised its right to redeem all of its outstanding 5.5% Cumulative Redeemable First Preferred Shares, Series 7 (Series 7 Shares) and all of its outstanding 5.6% Cumulative Redeemable First Preferred Shares, Series 8 (Series 8 Shares) at a price of $25.00 per Series 7 Share and $25.00 per Series 8 Share, respectively, for a total payment of $300 million. In addition, payment of $4 million was made for all accrued and unpaid dividends. As a result, we recorded a $300 million decrease in Noncontrolling interests.

11. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK
Our earnings, cash flows and Other Comprehensive Income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price (collectively, market 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 is 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 may be 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 2.8%.

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, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps. As at June 30, 2019, we do not have any pay floating-receive fixed interest rate swaps outstanding.

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 established 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 3.0%.

We also monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% 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.

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 reduce 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.

June 30, 2019	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	**—**	**—**	**37**	**37**	**(21)**	**16**
Interest rate contracts	**2**	**—**	**—**	**2**	**—**	**2**
Commodity contracts	**—**	**—**	**196**	**196**	**(54)**	**142**
	2	**—**	**233**	**235**	**(75)**	**160**
Deferred amounts and other assets						
Foreign exchange contracts	**14**	**—**	**99**	**113**	**(40)**	**73**
Commodity contracts	**1**	**—**	**23**	**24**	**(7)**	**17**
Other contracts	**1**	**—**	**1**	**2**	**(1)**	**1**
	16	**—**	**123**	**139**	**(48)**	**91**
Accounts payable and other						
Foreign exchange contracts	**(5)**	**—**	**(447)**	**(452)**	**21**	**(431)**
Interest rate contracts	**(258)**	**—**	**—**	**(258)**	**—**	**(258)**
Commodity contracts	**(1)**	**—**	**(183)**	**(184)**	**54**	**(130)**
	(264)	**—**	**(630)**	**(894)**	**75**	**(819)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**(13)**	**(1,381)**	**(1,394)**	**40**	**(1,354)**
Interest rate contracts	**(540)**	**—**	**—**	**(540)**	**—**	**(540)**
Commodity contracts	**—**	**—**	**(126)**	**(126)**	**7**	**(119)**
Other contracts	**(1)**	**—**	**(1)**	**(2)**	**1**	**(1)**
	(541)	**(13)**	**(1,508)**	**(2,062)**	**48**	**(2,014)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**9**	**(13)**	**(1,692)**	**(1,696)**	**—**	**(1,696)**
Interest rate contracts	**(796)**	**—**	**—**	**(796)**	**—**	**(796)**
Commodity contracts	**—**	**—**	**(90)**	**(90)**	**—**	**(90)**
Other contracts	**—**	**—**	**—**	**—**	**—**	**—**
	(787)	**(13)**	**(1,782)**	**(2,582)**	**—**	**(2,582)**

December 31, 2018	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Net Investment Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Accounts receivable and other						
Foreign exchange contracts	—	—	47	47	(37)	10
Interest rate contracts	22	—	—	22	(2)	20
Commodity contracts	2	—	427	429	(114)	315
	24	—	474	498	(153)	345
Deferred amounts and other assets						
Foreign exchange contracts	23	—	39	62	(39)	23
Interest rate contracts	5	—	—	5	—	5
Commodity contracts	19	—	33	52	(21)	31
	47	—	72	119	(60)	59
Accounts payable and other						
Foreign exchange contracts	(5)	—	(610)	(615)	37	(578)
Interest rate contracts	(163)	—	(178)	(341)	2	(339)
Commodity contracts	—	—	(273)	(273)	114	(159)
Other contracts	(1)	—	(4)	(5)	—	(5)
	(169)	—	(1,065)	(1,234)	153	(1,081)
Other long-term liabilities						
Foreign exchange contracts	(1)	(15)	(2,196)	(2,212)	39	(2,173)
Interest rate contracts	(201)	—	—	(201)	—	(201)
Commodity contracts	—	—	(178)	(178)	21	(157)
Other contracts	(1)	—	(1)	(2)	—	(2)
	(203)	(15)	(2,375)	(2,593)	60	(2,533)
Total net derivative asset/(liability)						
Foreign exchange contracts	17	(15)	(2,720)	(2,718)	—	(2,718)
Interest rate contracts	(337)	—	(178)	(515)	—	(515)
Commodity contracts	21	—	9	30	—	30
Other contracts	(2)	—	(5)	(7)	—	(7)
	(301)	(15)	(2,894)	(3,210)	—	(3,210)

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

June 30, 2019	2019	2020	2021	2022	2023	Thereafter[1]
Foreign exchange contracts - United States dollar forwards - purchase *(millions of United States dollars)*	**878**	**1**	**—**	**—**	**—**	**—**
Foreign exchange contracts - United States dollar forwards - sell *(millions of United States dollars)*	**2,422**	**4,893**	**3,608**	**2,422**	**1,804**	**1,856**
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**12**	**94**	**27**	**28**	**29**	**120**
Foreign exchange contracts - Euro forwards - purchase *(millions of Euro)*	**133**	**—**	**—**	**—**	**—**	**—**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**—**	**23**	**94**	**94**	**92**	**606**
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**—**	**—**	**72,500**	**—**	**—**
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**4,371**	**6,115**	**4,098**	**402**	**48**	**156**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**2,497**	**3,100**	**1,573**	**—**	**—**	**—**
Equity contracts *(millions of Canadian dollars)*	**29**	**20**	**34**	**—**	**—**	**—**
Commodity contracts - natural gas *(billions of cubic feet)*	**(44)**	**(14)**	**8**	**14**	**3**	**—**
Commodity contracts - crude oil *(millions of barrels)*	**10**	**3**	**—**	**—**	**—**	**—**
Commodity contracts - power *(megawatt per hour) (MW/H))*	**98**	**80**	**(3)**	**(43)**	**(43)**	**(43)**

1 As at June 30, 2019, thereafter includes an average net purchase/(sell) of power of (43) MW/H for 2024 through 2025.

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

The following table presents the effect of cash flow hedges and net investment hedges on our consolidated earnings and consolidated comprehensive income, before the effect of income taxes:

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(3)**	(3)	**(13)**	18
Interest rate contracts	**(285)**	17	**(581)**	117
Commodity contracts	**(18)**	(1)	**(21)**	(3)
Other contracts	**2**	12	**5**	(2)
Net investment hedges				
Foreign exchange contracts	**1**	(5)	**2**	11
	(303)	20	**(608)**	141
Amount of (gain)/loss reclassified from AOCI to earnings				
Foreign exchange contracts[1]	**—**	(2)	**2**	(3)
Interest rate contracts[2]	**40**	54	**72**	94
Commodity contracts[3]	**—**	—	**—**	(1)
Other contracts[4]	**6**	(6)	**(3)**	3
	46	46	**71**	93

1 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.

2 Reported within Interest expense in the Consolidated Statements of Earnings. Effective January 1, 2019 hedge ineffectiveness will no longer be measured or recorded. See Note 2 Changes in Accounting Policies.

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 $70 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 30 months as at June 30, 2019.

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.

	Three months ended June 30,		Six months ended June 30,	
	2019[1]	2018	**2019[1]**	2018
(millions of Canadian dollars)				
Unrealized gain/(loss) on derivative	**—**	(4)	**—**	3
Unrealized gain/(loss) on hedged item	**—**	3	**—**	(3)
Realized gain/(loss) on derivative	**—**	2	**—**	(1)
Realized gain/(loss) on hedged item	**—**	(2)	**—**	1

1 For the three and six months ended June 30, 2019, there are no outstanding fair value hedges.

Non-Qualifying Derivatives

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

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**412**	(277)	**1,028**	(701)
Interest rate contracts[2]	**—**	—	**178**	(2)
Commodity contracts[3]	**162**	(19)	**(99)**	156
Other contracts[4]	**—**	7	**5**	(2)
Total unrealized derivative fair value gain/(loss), net	**574**	(289)	**1,112**	(549)

1 For the respective six months ended periods, reported within Transportation and other services revenues (2019 - $550 million gain; 2018 - $555 million loss) and Net foreign currency gain/(loss) (2019 - $478 million gain; 2018 - $146 million loss) in the Consolidated Statements of Earnings.

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

3 For the respective six months ended periods, reported within Transportation and other services revenues (2019 - $25 million loss; 2018 - $3 million gain), Commodity sales (2019 - $490 million loss; 2018 - $10 million gain), Commodity costs (2019 - $392 million gain; 2018 - $127 million gain) and Operating and administrative expense (2019 - $24 million gain; 2018 - $16 million gain) in the Consolidated Statements of Earnings.

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

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at June 30, 2019. 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 strong investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated through maintenance and monitoring of credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

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

	June 30, 2019	December 31, 2018
(millions of Canadian dollars)		
Canadian financial institutions	**44**	28
United States financial institutions	**31**	107
European financial institutions	**80**	84
Asian financial institutions	**11**	6
Other[1]	**151**	337
	317	562

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

As at June 30, 2019, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association (ISDA) agreements. We held no cash collateral on derivative asset exposures as at June 30, 2019 and December 31, 2018.

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 EGI, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. We actively monitor the financial strength of large industrial customers, and in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we classify and provide for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

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

FAIR VALUE OF FINANCIAL INSTRUMENTS

We categorize our derivative instruments measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

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

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

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

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power contracts and NGL and natural gas contracts, basis swaps, commodity swaps, power and energy swaps, as well as options. We do not have any other financial instruments categorized in Level 3.

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

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

June 30, 2019	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**37**	**—**	**37**
Interest rate contracts	**—**	**2**	**—**	**2**
Commodity contracts	**6**	**27**	**163**	**196**
	6	**66**	**163**	**235**
Long-term derivative assets				
Foreign exchange contracts	**—**	**113**	**—**	**113**
Commodity contracts	**—**	**14**	**10**	**24**
Other contracts	**—**	**2**	**—**	**2**
	—	**129**	**10**	**139**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(452)**	**—**	**(452)**
Interest rate contracts	**—**	**(258)**	**—**	**(258)**
Commodity contracts	**(10)**	**(16)**	**(158)**	**(184)**
Other contracts	**—**	**—**	**—**	**—**
	(10)	**(726)**	**(158)**	**(894)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,394)**	**—**	**(1,394)**
Interest rate contracts	**—**	**(540)**	**—**	**(540)**
Commodity contracts	**—**	**(9)**	**(117)**	**(126)**
Other contracts	**—**	**(2)**	**—**	**(2)**
	—	**(1,945)**	**(117)**	**(2,062)**
Total net financial liabilities				
Foreign exchange contracts	**—**	**(1,696)**	**—**	**(1,696)**
Interest rate contracts	**—**	**(796)**	**—**	**(796)**
Commodity contracts	**(4)**	**16**	**(102)**	**(90)**
Other contracts	**—**	**—**	**—**	**—**
	(4)	**(2,476)**	**(102)**	**(2,582)**

December 31, 2018	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	47	—	47
Interest rate contracts	—	22	—	22
Commodity contracts	24	45	360	429
	24	114	360	498
Long-term derivative assets				
Foreign exchange contracts	—	62	—	62
Interest rate contracts	—	5	—	5
Commodity contracts	—	30	22	52
	—	97	22	119
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(615)	—	(615)
Interest rate contracts	—	(341)	—	(341)
Commodity contracts	(7)	(28)	(238)	(273)
Other contracts	—	(5)	—	(5)
	(7)	(989)	(238)	(1,234)
Long-term derivative liabilities				
Foreign exchange contracts	—	(2,212)	—	(2,212)
Interest rate contracts	—	(201)	—	(201)
Commodity contracts	—	(23)	(155)	(178)
Other contracts	—	(2)	—	(2)
	—	(2,438)	(155)	(2,593)
Total net financial liabilities				
Foreign exchange contracts	—	(2,718)	—	(2,718)
Interest rate contracts	—	(515)	—	(515)
Commodity contracts	17	24	(11)	30
Other contracts	—	(7)	—	(7)
	17	(3,216)	(11)	(3,210)

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

June 30, 2019	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	**(20)**	**Forward gas price**	**2.11**	**4.60**	**3.16**	**$/mmbtu[2]**
Crude	**7**	**Forward crude price**	**42.18**	**76.47**	**57.08**	**$/barrel**
Power	**(82)**	**Forward power price**	**27.63**	**78.91**	**56.83**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(58)**	**Forward gas price**	**1.04**	**6.95**	**1.36**	**$/mmbtu[2]**
Crude	**49**	**Forward crude price**	**38.74**	**91.45**	**69.70**	**$/barrel**
NGL	**2**	**Forward NGL price**	**0.15**	**1.67**	**0.45**	**$/gallon**
	(102)					

1 Financial and physical forward commodity contracts are valued using a market approach valuation technique.
2 One million British thermal units (mmbtu).

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

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

	Six months ended June 30,	
	2019	2018
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(11)**	(387)
Total gain/(loss)		
Included in earnings[1]	**103**	(7)
Included in OCI	**(20)**	(2)
Settlements	**(174)**	162
Level 3 net derivative liability at end of period	**(102)**	(234)

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

Our policy is to recognize transfers as at the last day of the reporting period. There were no transfers between levels as at June 30, 2019 or December 31, 2018.

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 (if any), plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. The carrying value of FVMA other long-term investments totaled $93 million and $102 million as at June 30, 2019 and December 31, 2018, respectively.

We have Restricted long-term investments held in trust totaling $389 million and $323 million as at June 30, 2019 and December 31, 2018, respectively, which are recognized at fair value.

We have a held to maturity preferred share investment carried at its amortized cost of $593 million and $478 million as at June 30, 2019 and December 31, 2018, 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 4.38%. The fair value of this preferred share investment approximates its face value of $580 million as at June 30, 2019 and December 31, 2018.

As at June 30, 2019 and December 31, 2018, our long-term debt had a carrying value of $64.9 billion and $63.9 billion, respectively, before debt issuance costs and a fair value of $70.0 billion and $64.4 billion, respectively. We also have noncurrent notes receivable carried at book value recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at June 30, 2019 and December 31, 2018, the noncurrent notes receivable had a carrying value of $93 million and $97 million, respectively, and a fair value of $93 million and $97 million, respectively.

The fair value of other financial assets and liabilities other than derivative instruments, other long-term investments, restricted long-term investments, long-term debt and non-current notes receivable described above approximate their carrying value due to the short period to maturity.

NET INVESTMENT HEDGES

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

During the six months ended June 30, 2019 and 2018, we recognized an unrealized foreign exchange gain of $250 million and an unrealized foreign exchange loss of $301 million, respectively, on the translation of United States dollar denominated debt and unrealized gains of $3 million and $10 million, respectively, on the change in fair value of our outstanding foreign exchange forward contracts in OCI. During the six months ended June 30, 2019 and 2018, we recognized realized losses of nil and $23 million, respectively, in OCI associated with the settlement of foreign exchange forward contracts and recognized realized losses of nil and $14 million, respectively, in OCI associated with the settlement of United States dollar denominated debt that had matured during the period. There was no ineffectiveness during the six months ended June 30, 2019 and 2018.

12. INCOME TAXES

The effective income tax rates for the three months ended June 30, 2019 and 2018 were 19.2% and (7.9)%, respectively, and for the six months ended June 30, 2019 and 2018 were 20.9% and (10.2)%, respectively. The period-over-period increase in the effective income tax rates is due to the buy-in of our sponsored vehicles which results in Enbridge being taxed on all of our sponsored vehicle earnings rather than on just our proportionate share, lower 2019 foreign tax rate differentials, 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.

13. PENSION AND OTHER POSTRETIREMENT BENEFITS

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Service cost	**51**	51	**102**	116
Interest cost	**50**	42	**101**	87
Expected return on plan assets	**(84)**	(80)	**(168)**	(162)
Amortization of actuarial loss	**8**	8	**16**	15
Plan curtailments	**—**	2	**—**	2
Amortization of prior service costs	**—**	—	**(1)**	(1)
Net periodic benefit costs	**25**	23	**50**	57

14. LEASES

We incur operating lease expenses related primarily to real estate, pipelines, storage and equipment. Our operating leases have remaining lease terms of 6 months to 29 years.

For the three and six months ended June 30, 2019, we incurred operating lease expenses of $28 million and $56 million, respectively. Operating lease expenses are reported under Operating and administrative expenses on the Consolidated Statements of Earnings.

For the three and six months ended June 30, 2019, operating lease payments to settle lease liabilities were $30 million and $61 million, respectively. Operating lease payments are reported under operating activities in the Consolidated Statements of Cash Flows.

Supplemental Statements of Financial Position Information

	June 30, 2019	January 1, 2019
(millions of Canadian dollars, except lease term and discount rate)		
Operating leases		
Operating lease right-of-use assets, net[1]	**738**	771
Operating lease liabilities - current[2]	**99**	86
Operating lease liabilities - long-term[3]	**714**	770
Total operating lease liabilities	**813**	856
Weighted average remaining lease term		
Operating leases	**14 years**	14 years
Weighted average discount rate		
Operating leases	**4.3%**	4.3%

1 Right-of-use assets are reported under Deferred amounts and other assets in the Consolidated Statements of Financial Position.
2 Current lease liabilities are reported under Accounts payable and other in the Consolidated Statements of Financial Position.
3 Long-term lease liabilities are reported under Other long-term liabilities in the Consolidated Statements of Financial Position.

As at June 30, 2019, we have operating lease commitments as detailed below:

	Operating leases
(millions of Canadian dollars)	
2019[1]	60
2020	124
2021	96
2022	91
2023	81
Thereafter	665
Total undiscounted lease payments	1,117
Less imputed interest	(304)
Total operating lease commitments	813

1 For the six months remaining in the 2019 fiscal year.

LESSOR

We have operating leases primarily related to natural gas and crude oil storage and processing facilities, rail cars, and wind power generation assets. Our leases have remaining lease terms of 1 month to 24 years.

	Three months ended June 30, 2019	Six months ended June 30, 2019
(millions of Canadian dollars)		
Operating lease income	**66**	**130**
Variable lease income	**85**	**185**
Total lease income	**151**	**315**

The following table sets out future minimum lease payments expected to be received under lease contracts where we are the lessor:

	Operating leases
(millions of Canadian dollars)	
2019[1]	131
2020	229
2021	196
2022	186
2023	178
Thereafter	2,391
Total undiscounted lease payments	3,311

1 For the six months remaining in the 2019 fiscal year.

15. CONTINGENCIES

We and our subsidiaries are involved in various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. 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 and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

16. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, the Partnerships, pursuant to which Enbridge fully and unconditionally guaranteed, on a senior unsecured basis, the payment obligations of the Partnerships with respect to the outstanding series of notes issued under the respective indentures of the Partnerships. Concurrently, the Partnerships entered into a subsidiary guarantee agreement pursuant to which they guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships are in the same position with respect to the net assets, income and cash flows of Enbridge as holders of Enbridge's outstanding guaranteed notes, and vice versa. Other than the Partnerships, Enbridge subsidiaries (including the subsidiaries of the Partnerships, collectively, the Subsidiary Non-Guarantors), are not parties to the subsidiary guarantee agreement and have not otherwise guaranteed any of Enbridge's outstanding series of senior notes.

Consenting SEP notes and EEP notes under Guarantee

SEP Notes[1]	EEP Notes[2]
Floating Rate Senior Notes due 2020	5.200% Notes due 2020
4.600% Senior Notes due 2021	4.375% Notes due 2020
4.750% Senior Notes due 2024	4.200% Notes due 2021
3.500% Senior Notes due 2025	5.875% Notes due 2025
3.375% Senior Notes due 2026	5.950% Notes due 2033
5.950% Senior Notes due 2043	6.300% Notes due 2034
4.500% Senior Notes due 2045	7.500% Notes due 2038
	5.500% Notes due 2040
	7.375% Notes due 2045

1 As at June 30, 2019, the aggregate outstanding principal amount of SEP notes was approximately US$3.9 billion.
2 As at June 30, 2019, the aggregate outstanding principal amount of EEP notes was approximately US$4.0 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
Senior Floating Rate Notes due 2020	4.770% Senior Notes due 2019
Senior Floating Rate Notes due 2020	4.530% Senior Notes due 2020
2.900% Senior Notes due 2022	4.850% Senior Notes due 2020
4.000% Senior Notes due 2023	4.260% Senior Notes due 2021
3.500% Senior Notes due 2024	3.160% Senior Notes due 2021
4.250% Senior Notes due 2026	4.850% Senior Notes due 2022
3.700% Senior Notes due 2027	3.190% Senior Notes due 2022
4.500% Senior Notes due 2044	3.940% Senior Notes due 2023
5.500% Senior Notes due 2046	3.940% Senior Notes due 2023
	3.950% Senior Notes due 2024
	3.200% Senior Notes due 2027
	6.100% Senior Notes due 2028
	7.220% Senior Notes due 2030
	7.200% Senior Notes due 2032
	5.570% Senior Notes due 2035
	5.750% Senior Notes due 2039
	5.120% Senior Notes due 2040
	4.240% Senior Notes due 2042
	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.560% Senior Notes due 2064

1 As at June 30, 2019, the aggregate outstanding principal amount of the Enbridge United States dollar denominated notes was approximately US$5.9 billion.
2 As at June 30, 2019, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $7.0 billion.

In accordance with Rule 3-10 of the SEC's Regulation S-X, which provides an exemption from the reporting requirements of the Securities Exchange Act of 1934 for subsidiary issuers of guaranteed securities and subsidiary guarantors, in lieu of filing separate financial statements for each of the Partnerships, we have included the accompanying condensed consolidating financial information with separate columns representing the following:

1. Enbridge Inc., the Parent Issuer and Guarantor;
2. SEP, a Subsidiary Issuer and Guarantor;
3. EEP, a Subsidiary Issuer and Guarantor;
4. Subsidiary Non-Guarantors, as defined herein;
5. Consolidating and elimination entries required to consolidate the Parent Issuer and Guarantor and its subsidiaries, including the Subsidiary Issuers and Guarantors, and
6. Enbridge Inc. and subsidiaries on a consolidated basis.

For the purposes of the condensed consolidating financial information only, investments in subsidiaries are accounted for under the equity method. In addition, the Condensed Consolidating Statements of Cash Flows present the intercompany loan and distribution activity, as well as cash collection and payments made on behalf of our subsidiaries, as cash activities. These intercompany investments and related activities eliminate on consolidation and are presented separately only for the purpose of the accompanying Condensed Consolidating Statements.

Condensed Consolidating Statements of Earnings and Comprehensive Income for the three months ended June 30, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	8,416	—	**8,416**
Gas distribution sales	—	—	—	755	—	**755**
Transportation and other services	—	—	—	4,092	—	**4,092**
Total operating revenues	—	—	—	13,263	—	**13,263**
Operating Expenses						
Commodity costs	—	—	—	8,129	—	**8,129**
Gas distribution costs	—	—	—	312	—	**312**
Operating and administrative	69	1	(2)	1,627	—	**1,695**
Depreciation and amortization	18	—	—	824	—	**842**
Total operating expenses	87	1	(2)	10,892	—	**10,978**
Operating income/(loss)	(87)	(1)	2	2,371	—	**2,285**
Income from equity investments	8	31	—	380	(6)	**413**
Equity earnings from consolidated subsidiaries	1,624	344	251	473	(2,692)	**—**
Other						
Net foreign currency gain	256	—	—	27	(143)	**140**
Other, including other income from affiliates	464	1	53	112	(565)	**65**
Interest expense	(322)	(84)	(136)	(690)	595	**(637)**
Earnings before income taxes	1,943	291	170	2,673	(2,811)	**2,266**
Income tax (expense)/recovery	(111)	12	—	(443)	106	**(436)**
Earnings	1,832	303	170	2,230	(2,705)	**1,830**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	2	**2**
Earnings attributable to controlling interests	1,832	303	170	2,230	(2,703)	**1,832**
Preference share dividends	(96)	—	—	—	—	**(96)**
Earnings attributable to common shareholders	1,736	303	170	2,230	(2,703)	**1,736**
Earnings	1,832	303	170	2,230	(2,705)	**1,830**
Total other comprehensive income/(loss)	(1,325)	(28)	14	(148)	113	**(1,374)**
Comprehensive income	507	275	184	2,082	(2,592)	**456**
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	51	**51**
Comprehensive income attributable to controlling interests	507	275	184	2,082	(2,541)	**507**

Condensed Consolidating Statements of Earnings and Comprehensive Income for the three months ended June 30, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	6,451	—	6,451
Gas distribution sales	—	—	—	856	—	856
Transportation and other services	—	—	—	3,438	—	3,438
Total operating revenues	—	—	—	10,745	—	10,745
Operating Expenses						
Commodity costs	—	—	—	6,278	—	6,278
Gas distribution costs	—	—	—	421	—	421
Operating and administrative	33	3	5	1,595	—	1,636
Depreciation and amortization	15	—	—	814	—	829
Impairment of long-lived assets	—	—	—	10	—	10
Total operating expenses	48	3	5	9,118	—	9,174
Operating income/(loss)	(48)	(3)	(5)	1,627	—	1,571
Income from equity investments	59	36	—	323	(55)	363
Equity earnings from consolidated subsidiaries	1,287	529	229	615	(2,660)	—
Other						
Net foreign currency gain/(loss)	(171)	2	—	65	61	(43)
Other, including other income/(expense) from affiliates	272	1	35	(3)	(276)	29
Interest expense	(286)	(72)	(137)	(477)	282	(690)
Earnings before income taxes	1,113	493	122	2,150	(2,648)	1,230
Income tax recovery	47	—	—	41	9	97
Earnings	1,160	493	122	2,191	(2,639)	1,327
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(167)	(167)
Earnings attributable to controlling interests	1,160	493	122	2,191	(2,806)	1,160
Preference share dividends	(89)	—	—	—	—	(89)
Earnings attributable to common shareholders	1,071	493	122	2,191	(2,806)	1,071
Earnings	1,160	493	122	2,191	(2,639)	1,327
Total other comprehensive income	948	11	6	162	(49)	1,078
Comprehensive income	2,108	504	128	2,353	(2,688)	2,405
Comprehensive income attributable to noncontrolling interests	—	—	—	—	(297)	(297)
Comprehensive income attributable to controlling interests	2,108	504	128	2,353	(2,985)	2,108

Condensed Consolidating Statements of Earnings and Comprehensive Income for the six months ended June 30, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	15,048	—	**15,048**
Gas distribution sales	—	—	—	2,631	—	**2,631**
Transportation and other services	—	—	—	8,440	—	**8,440**
Total operating revenues	—	—	—	26,119	—	**26,119**
Operating Expenses						
Commodity costs	—	—	—	14,694	—	**14,694**
Gas distribution costs	—	—	—	1,519	—	**1,519**
Operating and administrative	35	3	(1)	3,283	—	**3,320**
Depreciation and amortization	33	—	—	1,649	—	**1,682**
Total operating expenses	68	3	(1)	21,145	—	**21,215**
Operating income/(loss)	(68)	(3)	1	4,974	—	**4,904**
Income from equity investments	67	62	—	762	(65)	**826**
Equity earnings from consolidated subsidiaries	2,398	742	514	966	(4,620)	**—**
Other						
Net foreign currency gain/(loss)	1,477	—	—	(76)	(1,047)	**354**
Other, including other income from affiliates	794	1	94	235	(1,013)	**111**
Interest expense	(630)	(178)	(294)	(1,273)	1,053	**(1,322)**
Earnings before income taxes	4,038	624	315	5,588	(5,692)	**4,873**
Income tax (expense)/recovery	(220)	27		(1,039)	212	**(1,020)**
Earnings	3,818	651	315	4,549	(5,480)	**3,853**
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(35)	**(35)**
Earnings attributable to controlling interests	3,818	651	315	4,549	(5,515)	**3,818**
Preference share dividends	(191)	—	—	—	—	**(191)**
Earnings attributable to common shareholders	3,627	651	315	4,549	(5,515)	**3,627**
Earnings	3,818	651	315	4,549	(5,480)	**3,853**
Total other comprehensive income/(loss)	(2,603)	(44)	29	(868)	784	**(2,702)**
Comprehensive income	1,215	607	344	3,681	(4,696)	**1,151**
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	64	**64**
Comprehensive income attributable to controlling interests	1,215	607	344	3,681	(4,632)	**1,215**

Condensed Consolidating Statements of Earnings and Comprehensive Income for the six months ended June 30, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Operating revenues						
Commodity sales	—	—	—	13,719	—	13,719
Gas distribution sales	—	—	—	2,782	—	2,782
Transportation and other services	—	—	—	6,970	—	6,970
Total operating revenues	—	—	—	23,471	—	23,471
Operating Expenses						
Commodity costs	—	—	—	13,275	—	13,275
Gas distribution costs	—	—	—	1,745	—	1,745
Operating and administrative	100	4	9	3,164	—	3,277
Depreciation and amortization	29	—	—	1,624	—	1,653
Impairment of long lived assets	—	—	—	1,072	—	1,072
Total operating expenses	129	4	9	20,880	—	21,022
Operating income/(loss)	(129)	(4)	(9)	2,591	—	2,449
Income from equity investments	76	70	—	623	(71)	698
Equity earnings from consolidated subsidiaries	1,994	1,080	432	1,223	(4,729)	—
Other						
Net foreign currency gain/(loss)	(370)	4	—	7	131	(228)
Other, including other income from affiliates	518	2	65	36	(527)	94
Interest expense	(529)	(144)	(273)	(956)	556	(1,346)
Earnings before income taxes	1,560	1,008	215	3,524	(4,640)	1,667
Income tax recovery	134	—	—	18	18	170
Earnings	1,694	1,008	215	3,542	(4,622)	1,837
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	—	—	—	—	(143)	(143)
Earnings attributable to controlling interests	1,694	1,008	215	3,542	(4,765)	1,694
Preference share dividends	(178)	—	—	—	—	(178)
Earnings attributable to common shareholders	1,516	1,008	215	3,542	(4,765)	1,516
Earnings	1,694	1,008	215	3,542	(4,622)	1,837
Total other comprehensive income	2,250	30	14	415	(158)	2,551
Comprehensive income	3,944	1,038	229	3,957	(4,780)	4,388
Comprehensive loss attributable to noncontrolling interests	—	—	—	—	(444)	(444)
Comprehensive income attributable to controlling interests	3,944	1,038	229	3,957	(5,224)	3,944

Condensed Consolidating Statements of Financial Position as at June 30, 2019

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Assets						
Current assets						
Cash and cash equivalents	—	14	27	667	—	**708**
Restricted cash	9	—	—	50	—	**59**
Accounts receivable and other	153	2	2	6,100	—	**6,257**
Accounts receivable from affiliates	786	—	13	334	(1,048)	**85**
Short-term loans receivable from affiliates	3,417	—	4,523	6,225	(14,165)	**—**
Inventory	—	—	—	1,284	—	**1,284**
	4,365	16	4,565	14,660	(15,213)	**8,393**
Property, plant and equipment, net	161	—	—	93,041	—	**93,202**
Long-term loans receivable from affiliates	38,335	73	2,418	25,830	(66,656)	**—**
Investments in subsidiaries	78,955	19,932	6,009	14,762	(119,658)	**—**
Long-term investments	1,735	927	—	14,517	(648)	**16,531**
Restricted long-term investments	—	—	—	389	—	**389**
Deferred amounts and other assets	1,384	—	4	9,421	(1,257)	**9,552**
Intangible assets, net	227	—	—	1,988	—	**2,215**
Goodwill	—	—	—	33,342	—	**33,342**
Deferred income taxes	672	—	—	532	—	**1,204**
Total assets	125,834	20,948	12,996	208,482	(203,432)	**164,828**
Liabilities and equity						
Current liabilities						
Short-term borrowings	—	—	—	916	—	**916**
Accounts payable and other	718	52	5	6,240	141	**7,156**
Accounts payable to affiliates	1,158	819	524	(1,427)	(1,048)	**26**
Interest payable	273	53	68	232	—	**626**
Short-term loans payable to affiliates	430	3,113	2,681	7,941	(14,165)	**—**
Current portion of long-term debt	2,466	522	653	1,003	—	**4,644**
	5,045	4,559	3,931	14,905	(15,072)	**13,368**
Long-term debt	23,545	4,465	4,467	27,540	—	**60,017**
Other long-term liabilities	2,063	20	21	8,024	(1,257)	**8,871**
Long-term loans payable to affiliates	25,776	—	1,437	39,443	(66,656)	**—**
Deferred income taxes	—	282	—	5,120	4,365	**9,767**
	56,429	9,326	9,856	95,032	(78,620)	**92,023**
Equity						
Controlling interests[1]	69,405	11,622	3,140	113,450	(128,263)	**69,354**
Noncontrolling interests	—	—	—	—	3,451	**3,451**
	69,405	11,622	3,140	113,450	(124,812)	**72,805**
Total liabilities and equity	125,834	20,948	12,996	208,482	(203,432)	**164,828**

1 Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.

Condensed Consolidating Statements of Financial Position as at December 31, 2018

	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
(millions of Canadian dollars)						
Assets						
Current assets						
Cash and cash equivalents	—	16	—	502	—	518
Restricted cash	9	—	—	110	—	119
Accounts receivable and other	283	15	8	6,211	—	6,517
Accounts receivable from affiliates	726	—	13	(142)	(518)	79
Short-term loans receivable from affiliates	3,943	—	3,689	653	(8,285)	—
Inventory	—	—	—	1,339	—	1,339
	4,961	31	3,710	8,673	(8,803)	8,572
Property, plant and equipment, net	140	—	—	94,400	—	94,540
Long-term loans receivable from affiliates	10,318	73	2,539	1,344	(14,274)	—
Investments in subsidiaries	78,474	19,777	6,363	15,567	(120,181)	—
Long-term investments	4,561	987	—	14,841	(3,682)	16,707
Restricted long-term investments	—	—	—	323	—	323
Deferred amounts and other assets	1,700	9	17	8,558	(1,726)	8,558
Intangible assets, net	234	—	—	2,138	—	2,372
Goodwill	—	—	—	34,459	—	34,459
Deferred income taxes	817	—	—	229	328	1,374
Total assets	101,205	20,877	12,629	180,532	(148,338)	166,905
Liabilities and equity						
Current liabilities						
Short-term borrowings	—	—	—	1,024	—	1,024
Accounts payable and other	2,742	7	34	7,086	(6)	9,863
Accounts payable to affiliates	946	233	56	(677)	(518)	40
Interest payable	283	56	105	225	—	669
Short-term loans payable to affiliates	426	682	—	7,177	(8,285)	—
Current portion of long-term debt	1,853	—	683	723	—	3,259
	6,250	978	878	15,558	(8,809)	14,855
Long-term debt	22,893	7,276	6,943	23,215	—	60,327
Other long-term liabilities	2,428	2	30	8,100	(1,726)	8,834
Long-term loans payable to affiliates	76	—	1,502	12,696	(14,274)	—
Deferred income taxes	—	331	—	13,523	(4,400)	9,454
	31,647	8,587	9,353	73,092	(29,209)	93,470
Equity						
Controlling interests[1]	69,558	12,290	3,276	107,440	(123,094)	69,470
Noncontrolling interests	—	—	—	—	3,965	3,965
	69,558	12,290	3,276	107,440	(119,129)	73,435
Total liabilities and equity	101,205	20,877	12,629	180,532	(148,338)	166,905

1 Equity attributable to controlling interests for parent issuer and guarantor excludes reciprocal shareholding balance included within consolidating and elimination adjustments.

Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2019

(millions of Canadian dollars)	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
Net cash provided by operating activities	560	551	252	4,723	(1,416)	**4,670**
Investing activities						
Capital expenditures	(31)	—	—	(2,754)	—	**(2,785)**
Long-term investments and restricted long-term investments	(8)	(4)	—	(688)	—	**(700)**
Distributions from equity investments in excess of cumulative earnings	—	17	564	251	(564)	**268**
Additions to intangible assets	(36)	—	—	(64)	—	**(100)**
Affiliate loans, net	—	—	—	(140)	—	**(140)**
Contributions to subsidiaries	(2,336)	—	(3)	—	2,339	**—**
Return of share capital from subsidiary companies	4,921	—	—	—	(4,921)	**—**
Advances to affiliates	(32,520)	—	(1,407)	(41,213)	75,140	**—**
Repayment of advances to affiliates	4,748	—	422	9,930	(15,100)	**—**
Net cash (used in)/provided by investing activities	(25,262)	13	(424)	(34,678)	56,894	**(3,457)**
Financing activities						
Net change in short-term borrowings	—	—	—	(108)	—	**(108)**
Net change in commercial paper and credit facility draws	2,827	(2,017)	(1,017)	4,222	—	**4,015**
Debenture and term note issues, net of issue costs	—	—	—	1,195	—	**1,195**
Debenture and term note repayments	(1,050)	—	(1,189)	(345)	—	**(2,584)**
Contributions from noncontrolling interests	—	—	—	—	9	**9**
Distributions to noncontrolling interests	—	—	—	—	(100)	**(100)**
Contributions from redeemable noncontrolling interests	—	—	—	—	—	**—**
Distributions to redeemable noncontrolling interests	—	—	—	—	—	**—**
Contributions from parents	—	—	—	2,339	(2,339)	**—**
Distributions to parents	—	(1,014)	(328)	(5,650)	6,992	**—**
Redemption of preferred shares	—	—	—	(300)	—	**(300)**
Common shares issued	18	—	—	—	—	**18**
Preference share dividends	(191)	—	—	—	—	**(191)**
Common share dividends	(2,976)	—	—	—	—	**(2,976)**
Advances from affiliates	33,074	4,419	3,720	33,927	(75,140)	**—**
Repayment of advances from affiliates	(7,000)	(1,949)	(981)	(5,170)	15,100	**—**
Other	—	(5)	(6)	(25)	—	**(36)**
Net cash provided by/(used in) financing activities	24,702	(566)	199	30,085	(55,478)	**(1,058)**
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	(25)	—	**(25)**
Net increase/(decrease) in cash and cash equivalents and restricted cash	—	(2)	27	105	—	**130**
Cash and cash equivalents and restricted cash at beginning of period	9	16	—	612	—	**637**
Cash and cash equivalents and restricted cash at end of period	9	14	27	717	—	**767**

Condensed Consolidating Statements of Cash Flows for the six months ended June 30, 2018

(millions of Canadian dollars)	Parent Issuer and Guarantor	Subsidiary Issuer and Guarantor - SEP	Subsidiary Issuer and Guarantor - EEP	Subsidiary Non-Guarantors	Consolidating and elimination adjustments	Consolidated - Enbridge
Net cash (used in)/provided by operating activities	(79)	1,875	(145)	5,639	(752)	6,538
Investing activities						
Capital expenditures	(8)	—	—	(3,235)	—	(3,243)
Long-term investments and restricted long-term investments	(36)	(9)	—	(600)	34	(611)
Distributions from equity investments in excess of cumulative earnings	1,260	24	451	1,116	(1,711)	1,140
Additions to intangible assets	(20)	—	—	(405)	—	(425)
Affiliate loans, net	—	—	—	—	—	—
Proceeds from dispositions	—	—	—	4	—	4
Reimbursement of capital expenditures	—	—	—	—	—	—
Contributions to subsidiaries	(2,093)	(78)	(7)	—	2,178	—
Return of share capital from subsidiary companies	1,916	—	—	—	(1,916)	—
Advances to affiliates	(2,324)	—	(910)	(2,397)	5,631	—
Repayment of advances to affiliates	1,094	511	960	1,890	(4,455)	—
Other	—	—	—	(4)	—	(4)
Net cash (used in)/provided by investing activities	(211)	448	494	(3,631)	(239)	(3,139)
Financing activities						
Net change in short-term borrowings	—	—	—	(433)	—	(433)
Net change in commercial paper and credit facility draws	(931)	(1,397)	312	(150)	—	(2,166)
Debenture and term note issues, net of issue costs	2,556	—	—	981	—	3,537
Debenture and term note repayments	—	—	(509)	(1,638)	—	(2,147)
Contributions from noncontrolling interests	—	—	—	—	21	21
Distributions to noncontrolling interests	—	—	—	—	(425)	(425)
Contributions from redeemable noncontrolling interests	—	—	—	—	41	41
Distributions to redeemable noncontrolling interests	—	—	—	—	(174)	(174)
Contributions from parents	—	—	—	2,178	(2,178)	—
Distributions to parents	—	(924)	(331)	(3,627)	4,882	—
Common shares issued	14	—	—	—	—	14
Preference share dividends	(174)	—	—	—	—	(174)
Common share dividends	(1,493)	—	—	—	—	(1,493)
Advances from affiliates	368	—	2,029	3,234	(5,631)	—
Repayment of advances from affiliates	(43)	—	(1,847)	(2,565)	4,455	—
Other	—	(6)	(3)	9	—	—
Net cash provided by/(used in) financing activities	297	(2,327)	(349)	(2,011)	991	(3,399)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	—	—	—	35	—	35
Net increase/(decrease) in cash and cash equivalents and restricted cash	7	(4)	—	32	—	35
Cash and cash equivalents and restricted cash at beginning of period	2	14	—	571	—	587
Cash and cash equivalents and restricted cash at end of period	9	10	—	603	—	622

17. SUBSEQUENT EVENTS

On August 1, 2019, a rupture occurred on a 30-inch natural gas pipeline that makes up the Texas Eastern natural gas pipeline system in Lincoln County, Kentucky. The pipeline has been shut down as we respond to the incident. There has been one confirmed fatality. The National Transportation Safety Board (NTSB) has assumed control of the site. We are continuing to support the NTSB, the community and the community members who were impacted by the rupture.

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

INTRODUCTION

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

RECENT DEVELOPMENTS

STATE OF MINNESOTA PERMITTING TIMELINE FOR U.S. LINE 3 REPLACEMENT PROGRAM

On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the Minnesota Public Utilities Commission's (MNPUC's) adequacy determination of the Final Environmental Impact Statement (FEIS) for the U.S. L3R Program. While denying eight of the nine appealed items, the Minnesota Court of Appeals identified one issue that led them to reverse the adequacy determination. We will continue to consult with relevant state agencies about next steps.

At this time, we cannot determine when all necessary permits will be issued pending receipt of further information from the MNPUC on a timeline to complete this work. For further details refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.

TEXAS EASTERN PIPELINE RUPTURE

On August 1, 2019, a rupture occurred on a 30-inch natural gas pipeline that makes up the Texas Eastern natural gas pipeline system in Lincoln County, Kentucky. The pipeline has been shut down as we respond to the incident. There has been one confirmed fatality. The National Transportation Safety Board (NTSB) has assumed control of the site. We are continuing to support the NTSB, the community and the community members who were impacted by the rupture. The Texas Eastern natural gas pipeline system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York.

SECURED GROWTH PROJECTS UPDATE

On August 2, 2019, we announced that we are proceeding with $2 billion of new growth projects across several business segments. We now have a $19 billion inventory of secured projects at various stages of execution which are scheduled to come into service between 2019 and 2023. For further details refer to *Growth Projects - Commercially Secured Projects*.

MAINLINE SYSTEM CONTRACTING

On August 2, 2019, we launched an open season for transportation service on our Mainline System. The open season will provide shippers with the opportunity to enter into long-term contracts for priority access on the Mainline System upon maturity of the current Competitive Tolling Settlement agreement on June 30, 2021. The open season will run through October 2, 2019.

TEXAS EASTERN RATE CASE

On June 1, 2019 Texas Eastern Transmission, LP (Texas Eastern) put into effect its updated motion rates. These increased recourse rates are subject to refund and interest. There is a pending rate case proceeding before the FERC. Our shippers, the FERC and Texas Eastern are currently in settlement discussions with the expectation of achieving a negotiated settlement or commencing a rate case hearing before the end of the year.

RESULTS OF OPERATIONS

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars, except per share amounts)				
Segment earnings/(loss) before interest, income taxes and depreciation and amortization				
Liquids Pipelines	**1,992**	1,322	**4,064**	2,478
Gas Transmission and Midstream	**941**	1,014	**1,961**	1,140
Gas Distribution	**390**	370	**1,052**	1,006
Renewable Power Generation and Transmission	**94**	126	**218**	235
Energy Services	**221**	35	**227**	204
Eliminations and Other	**107**	(118)	**355**	(397)
Depreciation and amortization	**(842)**	(829)	**(1,682)**	(1,653)
Interest expense	**(637)**	(690)	**(1,322)**	(1,346)
Income tax (expense)/recovery	**(436)**	97	**(1,020)**	170
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	**2**	(167)	**(35)**	(143)
Preference share dividends	**(96)**	(89)	**(191)**	(178)
Earnings attributable to common shareholders	**1,736**	1,071	**3,627**	1,516
Earnings per common share	**0.86**	0.63	**1.80**	0.90
Diluted earnings per common share	**0.86**	0.63	**1.80**	0.90

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Three months ended June 30, 2019, compared with the three months ended June 30, 2018

Earnings Attributable to Common Shareholders were net positively impacted by $410 million due to certain unusual, infrequent or other factors, primarily explained by a non-cash, unrealized derivative fair value gain of $695 million ($551 million after-tax attributable to us) in 2019, compared with a loss of $282 million ($151 million after-tax attributable to us) in 2018, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks.

The positive factor above was partially offset by the following unusual, infrequent or other factors:

- a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market in our Energy Services business segment of $138 million ($105 million after-tax attributable to us) in 2019 compared with $16 million ($12 million after-tax attributable to us) in 2018; and
- the absence in 2019 of a deferred income tax recovery of $258 million ($190 million attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation assets.

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

After taking into consideration the factors above, the remaining $255 million increase in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to higher Flanagan South Pipeline, Seaway Crude Pipeline System and Bakken Pipeline System throughput period-over-period;
- contributions from new Gas Transmission and Midstream assets placed into service in 2018;
- increased earnings from our Gas Distribution segment due to higher distribution rates and customer base;
- increased earnings from our Energy Services segment due to the widening of certain location differentials during the second half of 2018 and the first half of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019;
- lower interest expense due to debt repayments from proceeds received on the sale of non-core assets in the second half of 2018;
- lower earnings attributable to noncontrolling interests in 2019 following the completion of the buy-in of our sponsored vehicles in the fourth quarter of 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Canadian to United States dollar average exchange rate (Average Exchange Rate) of $1.34 in 2019 compared with $1.29 in 2018, partially offset by realized losses arising from our foreign exchange risk management program.

The positive business factors above were partially offset by the following:

- the absence in 2019 of earnings from Midcoast Operating, L.P. and its subsidiaries (together, MOLP) and the provincially regulated portion of our Canadian gas gathering and processing businesses which were sold in 2018; and
- higher income tax expense due to higher earnings, the buy-in of our United States sponsored vehicles in the fourth quarter of 2018 and lower foreign tax rate differentials in 2019.

Six months ended June 30, 2019, compared with the six months ended June 30, 2018

Earnings Attributable to Common Shareholders were net positively impacted by $1,591 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- the absence in 2019 of a loss of $913 million ($701 million after-tax attributable to us) in 2018 on MOLP resulting from a revision to the fair value of the assets held for sale based on the sale price;
- the absence in 2019 of a loss of $154 million ($95 million after-tax attributable to us) in 2018 related to the Line 10 crude oil pipeline, which is a component of our Mainline System, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell;
- a non-cash, unrealized derivative fair value gain of $1,131 million ($828 million after-tax attributable to us) in 2019, compared with a loss of $559 million ($297 million after-tax attributable to us) in 2018, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks; and
- employee severance, transition and transformation costs of $65 million ($62 million after-tax attributable to us) in 2019, compared with $126 million ($123 million after-tax attributable to us) in 2018.

The positive factors above were partially offset by the following unusual, infrequent or other factors:

- a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market in our Energy Services business segment of $144 million ($110 million after-tax attributable to us) compared to $16 million ($12 million after-tax attributable to us) in 2018;
- the absence in 2019 of a gain of $63 million after-tax in 2018 that resulted from the impact of the Tax Cuts and Jobs Act on our United States Renewable Power Generation and Transmission assets; and
- the absence in 2019 of a deferred income tax recovery of $258 million ($190 million attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation assets.

After taking into consideration the factors above, the remaining $520 million increase in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to higher Flanagan South Pipeline, Seaway Crude Pipeline System and Bakken Pipeline System throughput period-over-period;
- contributions from new Gas Transmission and Midstream assets placed into service in 2018;
- increased earnings from our Gas Distribution segment due to colder weather experienced in our franchise areas, higher distribution rates and customer base, and the absence in 2019 of forecasted earnings sharing which was recorded in 2018;
- increased earnings from our Energy Services segment due to the widening of certain location differentials during the second half of 2018 and the first half of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019;
- lower earnings attributable to noncontrolling interests in 2019 following the completion of the buy-in of our sponsored vehicles in the fourth quarter of 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.33 in 2019 compared with $1.28 in 2018, partially offset by realized losses arising from our foreign exchange risk management program.

The positive business factors above were partially offset by the following:

- the absence in 2019 of earnings from MOLP and the provincially regulated portion of our Canadian gas gathering and processing businesses which were sold in 2018; and
- higher income tax expense due to higher earnings, the buy-in of our United States sponsored vehicles in the fourth quarter of 2018 and lower foreign tax rate differentials in 2019.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**1,992**	1,322	**4,064**	2,478

Three months ended June 30, 2019, compared with the three months ended June 30, 2018

EBITDA was positively impacted by $533 million due to certain unusual, infrequent or other factors, primarily explained by a non-cash, unrealized gain of $227 million in 2019 compared with a loss of $275 million in 2018 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks.

After taking into consideration the factor above, the remaining $137 million increase is primarily explained by the following significant business factors:

- higher Flanagan South Pipeline and Seaway Crude Pipeline System throughput period-over-period partially driven by the redirection of throughput to the Gulf Coast resulting from refinery outages in the United States Midwest;
- higher Bakken Pipeline System throughput period-over-period driven by strong production in the region;
- a higher International Joint Tariff (IJT) Benchmark Toll of US$4.15 in 2019 compared with US $4.07 in 2018;
- higher Mainline System ex-Gretna throughput of 2,661 thousands of barrels per day (kbpd) in 2019 compared with 2,636 kbpd in 2018 driven by an increase in supply and continuous capacity optimization; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.34 in 2019 compared with $1.29 in 2018.

The positive business factors above were partially offset by the unfavorable effect of a lower foreign exchange hedge rate used to lock-in United States dollar denominated revenues from the Canadian portion of the Mainline System.

Six months ended June 30, 2019, compared with the six months ended June 30, 2018

EBITDA was positively impacted by $1,347 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized gain of $570 million in 2019 compared with a loss of $573 million in 2018 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks; and
- the absence in 2019 of a loss of $154 million in 2018 related to Line 10, which is a component of our Mainline System, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell.

After taking into consideration the factors above, the remaining $239 million increase is primarily explained by the following significant business factors:

- higher Flanagan South Pipeline and Seaway Crude Pipeline System throughput period-over-period partially driven by the redirection of throughput to the Gulf Coast resulting from refinery outages in the United States Midwest;
- higher Bakken Pipeline System throughput period-over-period driven by strong production in the region;
- a higher IJT Benchmark Toll of US$4.15 in 2019 compared with US$4.07 in 2018;
- higher Mainline System ex-Gretna throughput of 2,689 kbpd in 2019 compared with 2,631 kbpd in 2018 driven by an increase in supply and continuous capacity optimization; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.33 in 2019 compared with $1.28 in 2018.

The positive business factors above were partially offset by the unfavorable effect of a lower foreign exchange hedge rate used to lock-in United States dollar denominated revenues from the Canadian portion of the Mainline System.

GAS TRANSMISSION AND MIDSTREAM

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**941**	1,014	**1,961**	1,140

Three months ended June 30, 2019, compared with the three months ended June 30, 2018

EBITDA was negatively impacted by the absence of contributions in 2019 of approximately $73 million from MOLP and the provincially regulated portion of our Canadian gas gathering and processing businesses which were sold in the second half of 2018.

After taking into consideration the absence of earnings from the sold assets, EBITDA was comparable period-over-period and is primarily explained by the following significant business factors:

- contributions from Valley Crossing Pipeline and certain other Offshore and US Transmission assets that were placed into service during 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.34 in 2019 compared with $1.29 in 2018.

The positive business factors above were partially offset by higher operating costs on our US Transmission assets primarily due to higher pipeline integrity costs.

Six months ended June 30, 2019, compared with the six months ended June 30, 2018

EBITDA was negatively impacted by the absence of contributions in 2019 of approximately $155 million from MOLP and the provincially regulated portion of our Canadian gas gathering and processing businesses which were sold in the second half of 2018.

After taking into consideration the absence of earnings from the sold assets, EBITDA was positively impacted by $923 million due to certain unusual, infrequent or other factors, primarily explained by the absence in 2019 of a loss of $913 million in 2018 on MOLP resulting from a revision to the fair value of the assets held for sale based on the sale price.

After taking into consideration the factor above, the remaining $53 million increase is explained by the following significant business factors:

- contributions from Valley Crossing Pipeline and certain other Offshore and US Transmission assets that were placed into service during 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of $1.33 in 2019 compared with $1.28 in 2018.

The positive business factors above were partially offset by higher operating costs on our US Transmission assets primarily due to higher pipeline integrity costs.

GAS DISTRIBUTION

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**390**	370	**1,052**	1,006

Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas) were amalgamated on January 1, 2019. The amalgamated company has been renamed EGI. Post amalgamation the financial results of EGI reflect the combined performance of EGD and Union Gas.

Three months ended June 30, 2019, compared with the three months ended June 30, 2018

EBITDA increased by $20 million primarily explained by the following significant business factors:

- increased earnings of $4 million resulting from colder weather experienced in our franchise service areas when compared to the corresponding period in 2018; and
- increased earnings from higher distribution charges primarily resulting from increases in distribution rates and customer base.

Six months ended June 30, 2019, compared with the six months ended June 30, 2018

EBITDA was negatively impacted by $22 million due to certain unusual, infrequent or other factors, primarily explained by employee severance costs of $37 million in 2019 related to the amalgamation of EGD and Union Gas. This negative factor was partially offset by the absence in 2019 of a negative equity earnings adjustment of $9 million in 2018 at our equity investee, Noverco Inc., arising from the Tax Cuts and Jobs Act in the United States.

After taking into consideration the factors above, the remaining $68 million increase is primarily explained by the following significant business factors:

- increased earnings of $42 million resulting from colder weather experienced in our franchise service areas when compared to the corresponding period in 2018;
- increased earnings from higher distribution charges primarily resulting from increases in distribution rates and customer base; and
- the absence in 2019 of forecasted earnings sharing which was recorded in 2018 under EGD's previous incentive rate structure.

RENEWABLE POWER GENERATION AND TRANSMISSION

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**94**	126	**218**	235

Three months ended June 30, 2019, compared with the three months ended June 30, 2018

EBITDA decreased by $32 million primarily due to weaker wind resources at United States wind facilities.

Six months ended June 30, 2019, compared with the six months ended June 30, 2018

EBITDA was positively impacted by $24 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- the absence in 2019 of an asset impairment charge of $22 million in 2018 from our equity investment in NRGreen Power Limited Partnership related to the Chickadee Creek waste heat recovery facility in Alberta; and
- the absence in 2019 of a loss of $11 million in 2018 representing our share of losses incurred by our equity investee, Rampion Offshore Wind Limited, primarily due to the repair and restoration of damaged power transmission cables, for which we are seeking reimbursement.

After taking into consideration the factors above, the remaining $41 million decrease is primarily explained by the following significant business factors:

- weaker wind resources at United States wind facilities; and
- the absence in 2019 of $11 million in 2018 from a positive arbitration settlement related to our Canadian wind facilities.

The negative business factors above were partially offset by contributions from the Rampion Offshore Wind Project in 2019 which reached full operating capacity in the second quarter of 2018.

ENERGY SERVICES

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**221**	35	**227**	204

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

Three months ended June 30, 2019, compared with the three months ended June 30, 2018

EBITDA was net positively impacted by $160 million due to certain unusual, infrequent or other factors, primarily explained by a non-cash, unrealized gain of $271 million in 2019 compared with a loss of $11 million in 2018 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices. This positive factor was partially offset by a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market of $138 million in 2019 compared with $16 million in 2018.

After taking into consideration the factors above, the remaining $26 million increase is primarily due to increased earnings from Energy Services' crude operations as a result of the widening of certain location and quality differentials during the second half of 2018 and the first quarter of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019.

Six months ended June 30, 2019, compared with the six months ended June 30, 2018

EBITDA was negatively impacted by $157 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of $107 million in 2019 compared with a gain of $136 million in 2018 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices; and
- a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market of $144 million in 2019 compared with $16 million in 2018.

After taking into consideration the factors above, the remaining $180 million increase is primarily due to increased earnings from Energy Services' crude operations as a result of the widening of certain location and quality differentials during the second half of 2018 and the first quarter of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019.

ELIMINATIONS AND OTHER

	Three months ended June 30,		Six months ended June 30,	
	2019	2018	**2019**	2018
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**107**	(118)	**355**	(397)

Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements, which are not allocated to business segments. Eliminations and Other also includes the impact of new business development activities and corporate investments.

Three months ended June 30, 2019, compared with the three months ended June 30, 2018

EBITDA was positively impacted by $245 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of $192 million in 2019 compared with $5 million in 2018 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- employee severance, transition and transformation costs of $18 million in 2019 compared with $26 million in 2018; and
- the absence in 2019 of asset monetization transaction costs of $20 million in 2018.

After taking into consideration the factors above, the remaining $20 million decrease is primarily explained by the following significant business factors:

- higher operating and administrative costs in the second quarter of 2019 due to the timing of the recovery of certain operating and administrative allocated to the business segments in 2018; and
- a realized loss of $61 million in 2019 compared with a loss of $53 million in 2018 related to settlements under our foreign exchange risk management program, which partially offset the positive impact of a strengthening United States dollar on our United States business segments.

Six months ended June 30, 2019, compared with the six months ended June 30, 2018

EBITDA was positively impacted by $690 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of $444 million in 2019 compared with a loss of $131 million in 2018 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- employee severance, transition and transformation costs of $27 million in 2019 compared with $88 million in 2018; and
- the absence in 2019 of asset monetization transaction costs of $20 million in 2018.

After taking into consideration the factors above, the remaining $62 million increase is primarily explained by lower operating and administrative costs in the first half of 2019 and the timing of the recovery of certain operating and administrative costs allocated to the business segments, which were more heavily weighted to the second half of 2018.

The positive business factors above were partially offset by a realized loss of $116 million in 2019 compared with a loss of $95 million in 2018 related to settlements under our foreign exchange risk management program, which partially offset the positive impact of a strengthening United States dollar on our United States business segments.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

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

	Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status	Expected In-Service Date
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1. Other - Canada[3]	100%	$0.3 billion	$0.3 billion	Complete	In-service
2. Gray Oak Pipeline Project	22.8%	US$0.7 billion	US$0.4 billion	Under construction	Q4 - 2019
3. Canadian Line 3 Replacement Program	100%	$5.3 billion	$4.6 billion	Substantially complete	2H - 2020
4. U.S. Line 3 Replacement Program	100%	US$2.9 billion	US$1.2 billion	Pre-construction	2H - 2020[4]
5. Other - United States[5]	100%	US$0.5 billion	US$0.4 billion	Various stages	2020 - 2021
GAS TRANSMISSION AND MIDSTREAM					
6. Atlantic Bridge	100%	US$0.6 billion	US$0.5 billion	Under construction	1H - 2020
7. Spruce Ridge Project	100%	$0.5 billion	$0.1 billion	Pre-construction	2H - 2021
8. T-South Expansion Program	100%	$1.0 billion	$0.3 billion	Pre-construction	2H - 2021
9. Other - United States[6]	100%	US$1.1 billion	US$0.3 billion	Various stages	2019 - 2023
GAS DISTRIBUTION					
10. Other - Canada	100%	$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2020
11. Dawn-Parkway Expansion	100%	$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2021
RENEWABLE POWER GENERATION AND TRANSMISSION					
12. Hohe See Offshore Wind Project and Expansion	25%	$1.1 billion (€0.67 billion)	$0.7 billion (€0.5 billion)	Under construction	Q4 - 2019
13. Other - Canada	25%	$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2021
14. Saint-Nazaire France Offshore Wind Project	50%	$1.8 billion (€1.2 billion)	No significant expenditures to date	Pre-construction	2H - 2022

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.
2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to June 30, 2019.
3 Athabasca Oil Corporation Lateral Acquisition placed into service in the first quarter of 2019.
4 Update to in-service date pending MNPUC review of FEIS remediation.
5 Includes the Lakehead System Mainline Expansion - Line 61. Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program.
6 Includes the US$0.2 billion Stratton Ridge Project placed into service in the second quarter of 2019.

A full description of each of our projects is provided in our Annual Report on Form 10-K. Significant updates that have occurred since the date of filing are discussed below.

LIQUIDS PIPELINES

- **Gray Oak Pipeline Project -** a crude oil pipeline project connecting West Texas to destinations in the Corpus Christi and Sweeny/Freeport markets. The pipeline is a joint development with Phillips 66 and could have an ultimate capacity of approximately 900,000 barrels per day, subject to additional shipper commitments. Project execution forecasts were revised to reflect updated construction cost estimates and timing, with an expected in-service date in the fourth quarter of 2019.

GAS TRANSMISSION AND MIDSTREAM

- **Atlantic Bridge -** expansion of the Algonquin Gas Transmission systems to transport 133 million cubic feet per day (mmcf/d) of natural gas to the New England Region. The expansion primarily consists of various meter station additions, the replacement of a natural gas pipeline in Connecticut and New York, compression additions in Connecticut, and a new compressor station in Massachusetts. The meter stations were placed into service in 2017 and 2018. The Connecticut portion of the project was placed into service in the fourth quarter of 2017. The New York portion of the project achieved partial in-service in November 2018 and the revised expected full in-service date is the fourth quarter of 2019, upon which we will begin earning incremental revenues. The final Massachusetts portion of the project is expected to be in service in the first half of 2020.

- **Spruce Ridge Project** - a natural gas pipeline expansion of Westcoast Energy Inc.'s British Columbia (BC) Pipeline in northern BC. The project will provide additional capacity of up to 402 mmcf/d with a revised in-service date in the second half of 2021.

GAS DISTRIBUTION

- **Dawn-Parkway Expansion** - the expansion of the existing Dawn to Parkway gas transmission system, which provides transportation service from Dawn to the Greater Toronto Area. The project will provide additional capacity of approximately 75 mmcf/d with an expected in-service date by the end of 2021.

RENEWABLE POWER GENERATION AND TRANSMISSION

- **Saint Nazaire France Offshore Wind Project -** a wind project located off the west coast of France that will generate approximately 480 megawatts. We hold an effective 50% interest with EDF Renouvelables. Project revenues are backed by a 20-year fixed price power purchase agreement with added power production protection. Our share of the total investment in the project is $1.8 billion, with an equity contribution of $0.3 billion. The remainder of the construction will be financed through non-recourse project level debt.

GROWTH PROJECTS - REGULATORY MATTERS

United States Line 3 Replacement Program
On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the MNPUC's adequacy determination of the FEIS for the U.S. L3R Program. While denying eight of the nine appealed items, the Minnesota Court of Appeals identified one issue that led them to reverse the adequacy determination. The Minnesota Court of Appeals remanded and directed the MNPUC to perform spill modeling analysis within the Lake Superior Watershed. On July 3, 2019, several parties to the original appeal of the FEIS, petitioned for Minnesota Supreme Court review of the Minnesota Court of Appeals June 3, 2019 decision. The MNPUC and we responded to those petitions on July 23, 2019 and the Minnesota Supreme Court is expected to decide whether to accept or decline further review by September 3, 2019.

As for environmental permits, the spill modeling required by the Court of Appeals is a prerequisite to finalizing other state permits. At this time, we cannot determine when all necessary permits will be issued pending receipt of further information from the MNPUC on a timeline to complete this work. The MNPUC's statement on July 3, 2019 indicated that the agency will seek public comment and work expeditiously to address the FEIS deficiency. Additionally, the State permitting agencies' have confirmed they will continue to advance their permitting work in parallel with MNPUC process. We expect to hear from the MNPUC regarding their updated process and timelines, after which we expect permitting agencies to re-align their timelines to the MNPUC process.

Construction costs for the Line 3 Replacement Program are tracking below budget in Canada and above budget in the United States due to permitting delays. Depending on the final in-service date, there is a risk that the project will exceed our total cost estimate of $9 billion.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

LIQUIDS PIPELINES

- **Texas COLT Offshore Loading Project -** the Texas COLT Offshore Loading Project will facilitate the direct loading of very large crude carriers from Freeport, Texas. The project consists of a terminal, a 42-inch offshore pipeline, platform and two single point mooring systems with connectivity to all key North American supply basins. During the first quarter of 2019 we acquired the position previously held by Kinder Morgan Inc. During the second quarter of 2019 the United States Maritime Administration and the United States Coast Guard temporarily suspended processing of Texas COLT Offshore Loading Project's deepwater port license application to assess further information regarding the addition of a marine vapor control system to the original project design. We continue to work closely with Federal and State permitting agencies and expect the project to be placed into service by 2022.

GAS TRANSMISSION AND MIDSTREAM

- **Texas Eastern Venice Lateral Project -** a reversal and expansion of Texas Eastern's line 40 from its existing Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of the Texas Eastern's Larose compressor station. The project will deliver 1.5 billion cubic feet of feed gas to Venture Global's proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The project is expected to be placed into service by 2022.

We also have a large portfolio of additional projects under development that have not yet progressed to the point of public announcement.

LIQUIDITY AND CAPITAL RESOURCES

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

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not require the use of equity funding alternatives and was the leading principle behind the suspension of our Dividend Reinvestment and Share Purchase Plan in November 2018.

CAPITAL MARKET ACCESS

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

Credit Facilities and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities as at June 30, 2019:

	Maturity Dates	Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2021-2024	**6,511**	**4,850**	**1,661**
Enbridge (U.S.) Inc.	2021-2024	**7,187**	**5,017**	**2,170**
Enbridge Pipelines Inc.	2020	**3,000**	**2,314**	**686**
Enbridge Gas Inc.	2019-2021	**2,017**	**926**	**1,091**
Total committed credit facilities		**18,715**	**13,107**	**5,608**

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

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, EGI, EEP and SEP. We also increased existing facilities or obtained new facilities for Enbridge, Enbridge (U.S.) Inc. and EGI to substantially replace the terminated facilities. As a result, our total credit facility availability increased by approximately $444 million Canadian dollar equivalent.

On May 16, 2019, Enbridge Inc. entered into a three year, extendible credit facility for $641 million (¥52.5 billion) with a syndicate of Japanese banks.

In addition to the committed credit facilities noted above, we maintain $887 million of uncommitted demand credit facilities, of which $571 million were unutilized as at June 30, 2019. As at December 31, 2018, we had $807 million of uncommitted credit facilities, of which $548 million were unutilized.

Our net available liquidity of $6,316 million as at June 30, 2019, was inclusive of $708 million of unrestricted cash and cash equivalents as reported in the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at June 30, 2019, we were in compliance with all debt covenants and we expect to continue to comply with such covenants.

LONG-TERM DEBT ISSUANCES

During the six months ended June 30, 2019, we completed the following long-term debt issuances:

Company	Issue Date		Principal Amount
(millions of Canadian dollars)			
Enbridge Pipelines Inc.			
	February 2019	3.52% medium-term notes due February 2029	$600
	February 2019	4.33% medium-term notes due February 2049	$600

LONG-TERM DEBT REPAYMENTS

During the six months ended June 30, 2019, we completed the following long-term debt repayments:

Company	Retirement/ Repayment Date		Principal Amount
(millions of Canadian dollars, unless otherwise stated)			
Enbridge Inc.			
Repayment			
	February 2019	4.10% medium-term notes	$300
	May 2019	Floating rate notes	$750
Enbridge Energy Partners, L.P.			
Redemption			
	February 2019	8.05% fixed/floating rate junior subordinated notes due 2067	US$400
Repayment			
	March 2019	9.88% senior notes	US$500
Enbridge Pipelines (Southern Lights) L.L.C.			
Repayment			
	June 2019	3.98% medium-term notes due 2040	US$23
Westcoast Energy Inc.			
Repayment			
	January 2019	5.60% medium-term notes	$250
	January 2019	5.60% medium-term notes	$50
	May 2019	6.90% senior secured notes due 2019	$13
	May 2019	4.34% senior secured notes due 2019	$2

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model support our strong credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at June 30, 2019, our debt capitalization ratio was 47.4%, compared with 46.8% as at December 31, 2018.

There are no material restrictions on our cash. Total restricted cash of $59 million, as reported in the Consolidated Statements of Financial Position, primarily includes cash collateral and amounts received in respect of specific shipper commitments. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative uses by us.

Excluding current maturities of long-term debt, we had a negative working capital position as at June 30, 2019. The major contributing factor to the negative working capital position was the ongoing funding of our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due. As at June 30, 2019 and December 31, 2018, our net available liquidity totaled $6,316 million and $9,409 million, respectively.

SOURCES AND USES OF CASH

	Six months ended June 30,	
	2019	2018
(millions of Canadian dollars)		
Operating activities	**4,670**	6,538
Investing activities	**(3,457)**	(3,139)
Financing activities	**(1,058)**	(3,399)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(25)**	35
Increase in cash and cash equivalents and restricted cash	**130**	35

Significant sources and uses of cash for the six months ended June 30, 2019 and June 30, 2018 are summarized below:

Operating Activities

- The decrease in cash flow provided by operations during the first half of 2019 was primarily driven by changes in operating assets and liabilities. Our operating assets and liabilities fluctuate in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally.
- The factor above was partially offset by stronger contributions from our operating segments and contributions from new assets placed into service as discussed under *Results of Operations*.

Investing Activities

- The increase in cash used in investing activities during the first half of 2019 was attributable to activity in 2018 that was not present in 2019, primarily relating to a distribution received in the second quarter of 2018 from Sabal Trail Transmission, LLC (Sabal Trail) as a partial return of capital for construction and development costs previously funded by Sabal Trail's partners.
- The factor above is partially offset by lower additions to intangible assets in the first half of 2019 compared with the same period in 2018, primarily due to the wind down of the Cap and Trade program in the fourth quarter of 2018.
- We are continuing with the execution of our growth capital program which is further described in *Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

Financing Activities

- The decrease in cash used in financing activities during the first half of 2019 was primarily attributable to a net increase in commercial paper and credit facility draws, partially offset by higher repayments of maturing long-term debt and a decrease of long-term debt issued in 2019 when compared with the same period in 2018.

- Our common share dividend payments increased period-over-period primarily due to the increase in the common share dividend rate and an increase in the number of common shares outstanding in connection with the buy-in of our sponsored vehicles in the fourth quarter of 2018. These factors were partially offset by the suspension of our Dividend Reinvestment and Share Purchase Plan in the fourth quarter of 2018. In addition, in the first quarter of 2019, Westcoast Energy Inc. redeemed all of its outstanding Series 7 and Series 8 preference shares for a total payment of $300 million.
- Distributions to noncontrolling interests and redeemable noncontrolling interests decreased as a result of the buy-in of our sponsored vehicles in the fourth quarter 2018.

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Eddystone Rail Legal Matter

In February 2017, our subsidiary Eddystone Rail Company, LLC (Eddystone Rail) filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania, seeking damages in excess of US$140 million. On September 7, 2018, the United States District Court for the Eastern District of Pennsylvania granted Eddystone Rail's motion to amend its complaint to add several affiliates of the corporate defendants as additional defendants (the Amended Complaint). Eddystone Rail’s chances of success on its Amended Complaint cannot be predicted at this time. Defendants have filed Answers and Counterclaims which, together with subsequent amendments, seek damages from Eddystone Rail in excess of US$32 million. The defendants’ chances of success on their counterclaims cannot be predicted at this time.

Dakota Access Pipeline

In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed motions with the United States Court for the District of Columbia contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit the Dakota Access Pipeline (DAPL). The Oglala Sioux and Yankton Sioux Tribes also filed claims in the case to challenge the Army Corps permit and environmental review process. In August 2018, in response to a Court order to reconsider components of its environmental analysis, the Army Corps issued its decision that no supplemental environmental analysis was required. All four Tribes have since amended their complaints to include claims challenging the adequacy of the Army Corps’ supplemental environmental analysis. An administrative record dispute has since been resolved and the case will now proceed to summary judgment briefing on the merits of the plaintiff's claims challenging the adequacy the Army Corps' remand process. According to the United States Court for the District of Columbia's schedule, the filing of summary judgment briefs will proceed throughout the remainder of the year.

Line 5 Dual Pipelines

In December 2018, Michigan law PA 359 was enacted which created the Mackinac Straits Corridor Authority (Corridor Authority) and authorized an agreement between us and the Corridor Authority for the construction of a tunnel under the Straits of Mackinac (Straits) to house a replacement for the Line 5 Dual Pipelines that currently cross the Straits (the Tunnel Project). On December 19, 2018, we entered into a Tunnel Project agreement with the Government of Michigan under the administration of former Governor Snyder. On March 28, 2019, the new Michigan Attorney General issued an opinion finding the Michigan law PA 359 unconstitutional. Immediately following the Attorney General’s opinion that the Michigan law was unconstitutional, the new Michigan Governor Whitmer issued a directive to Michigan agencies to cease any action implementing the statute.

To resolve the legal uncertainty created by the Attorney General's opinion and the directive issued by Governor Whitmer, on June 6, 2019, we filed a complaint with the Michigan Court of Claims to establish the constitutional validity of Michigan law PA 359 and enforceability of various agreements entered into between us and the State of Michigan related to the construction of the Tunnel Project. On June 11, 2019, State officials confirmed that we had valid permits to conduct specified geotechnical work which is ongoing and necessary to prepare for Tunnel Project construction, but reiterated the Administration's position that Michigan law PA 359 is unconstitutional and all agreements entered into under that statute by us and the State of Michigan are null and void.

On June 27, 2019, we received two separate court filings made by the Michigan Attorney General. In one filing the Michigan Attorney General has asked the Michigan Court of Claims to dismiss the claim we filed on June 6, 2019. We will respond in due course as part of the Michigan Court of Claims process and we are comfortable with the case we can make as described in our filing June 6, 2019. The second filing requests the Michigan Circuit Court to declare the easement that we have for the operation of the dual pipelines in the Straits to be invalid and enjoin continued operation of the dual pipelines in the Straits "as soon as possible after a reasonable notice period to allow orderly adjustments by affected parties". We will vigorously defend this action.

Line 5 Easement

For over six years, we have been in discussions with the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) to resolve the Band's concerns regarding the Line 5 pipeline within the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. We hold an existing easement authorizing the majority of Line 5's crossing within the Reservation issued in 1993 that remains in effect through 2043. On July 23, 2019, the Band filed a Complaint in the United States District Court of Wisconsin alleging that our continued use of Line 5 to transport crude oil and other liquids across the Reservation is a public nuisance under federal and state law, constitutes a trespass and alleging that the Band is entitled to ejectment of Line 5 from certain parcels within the Reservation. The Band seeks an order prohibiting us from using Line 5 to transport crude oil and natural gas liquids across the Reservation and removing the pipeline from the Reservation. The Band has not sought a Temporary Injunction to immediately discontinue operation of Line 5. While Line 5 continues to operate, the Band's action could impact our ability to operate the pipeline on the Reservation. We have 60 days to respond to the Complaint and plan to continue working with the Band to find solutions to address their concerns.

OTHER LITIGATION

We and our subsidiaries are involved in various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

CAPITAL EXPENDITURE COMMITMENTS

We have signed contracts for the purchase of services, pipe and other materials totaling approximately $2.4 billion which are expected to be paid over the next five years.

TAX MATTERS

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

CHANGES IN ACCOUNTING POLICIES

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as at June 30, 2019, and based upon this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these controls and procedures are effective in ensuring that information required to be disclosed by us in reports that we file with or submit to the SEC and the Canadian Securities Administrators is recorded, processed, summarized and reported within the time periods required.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we have evaluated changes in internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the fiscal quarter ended June 30, 2019 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are involved in various legal and regulatory actions and proceedings which arise in the ordinary course of business. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations. Refer to Part I. Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates* and *Growth Projects - Regulatory Matters* for discussion of other legal proceedings.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, careful consideration should be given to the factors discussed in Part I. Item 1A. *Risk Factors* of our Annual Report on Form 10-K for the year ended December 31, 2018, which could materially affect our financial condition or future results. There have been no material modifications to those risk factors.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

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

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated as of September 5, 2016, by and among Spectra Energy Corp, Enbridge Inc. and Sand Merger Sub, Inc. (incorporated by reference to Exhibit 2.1 to Enbridge's Registration Statement on Form F-4 filed September 23, 2017)
2.2	Agreement and Plan of Merger, dated as of August 24, 2018, by and among Spectra Energy Partners, LP, Spectra Energy Partners (DE) GP, LP, Enbridge Inc., Enbridge (U.S.) Inc., Autumn Acquisition Sub, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc., Spectra Energy Corp, Spectra Energy Capital, LLC and Spectra Energy Transmission, LLC. (incorporated by reference to Exhibit 2.1 to Enbridge's Form 8-K filed August 24, 2018)
2.3	Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Partners, L.P., Enbridge Energy Company, Inc., Enbridge Energy Management, L.L.C., Enbridge Inc., Enbridge (U.S.) Inc., Winter Acquisition Sub II, LLC, and solely for the purposes of Articles I, II and XI, Enbridge US Holdings Inc. (incorporated by reference to Exhibit 2.1 to Enbridge's Form 8-K filed September 18, 2018)
2.4	Agreement and Plan of Merger, dated as of September 17, 2018, by and among Enbridge Energy Management, L.L.C., Enbridge Inc., Winter Acquisition Sub I, Inc., and solely for the purposes of Article I, Section 2.4 and Article X, Enbridge Energy Company, Inc. (incorporated by reference to Exhibit 2.2 to Enbridge's Form 8-K filed September 18, 2018)
2.5	Arrangement Agreement, dated as of September 17, 2018, by and between Enbridge Inc. and Enbridge Income Fund Holdings Inc. (incorporated by reference to Exhibit 2.3 to Enbridge's Form 8-K filed September 18, 2018)
10.8*	Form of Enbridge Inc. 2019 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Award Agreement - Retention Award Version
31.1*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.

SIGNATURES

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

ENBRIDGE INC.
(Registrant)

Date:	August 2, 2019	By:	/s/ Al Monaco Al Monaco President and Chief Executive Officer
Date:	August 2, 2019	By:	/s/ Colin K. Gruending Colin K. Gruending Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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