ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

September 30, 2026

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(unaudited; millions of Canadian dollars, except per share amounts)				
Operating revenues				
Commodity sales	**14,851**	8,396	**50,628**	26,069
Gas distribution sales	**1,338**	1,303	**7,318**	6,765
Transportation and other services	**4,888**	4,940	**14,806**	15,183
Total operating revenues *(Note 3)*	**21,077**	14,639	**72,752**	48,017
Operating expenses				
Commodity costs	**14,736**	8,207	**49,979**	25,550
Gas distribution costs	**248**	280	**2,754**	2,444
Operating and administrative	**2,465**	2,483	**7,394**	7,264
Depreciation and amortization	**1,490**	1,398	**4,352**	4,197
Impairment of long-lived assets *(Note 4)*	**—**	—	**—**	330
Total operating expenses	**18,939**	12,368	**64,479**	39,785
Operating income	**2,138**	2,271	**8,273**	8,232
Income from equity investments	**517**	451	**1,590**	1,690
Other income/(expense) *(Note 13)*	**273**	(297)	**59**	1,192
Interest expense	**(1,049)**	(1,262)	**(3,666)**	(3,777)
Earnings before income taxes	**1,879**	1,163	**6,256**	7,337
Income tax expense	**(438)**	(316)	**(1,467)**	(1,679)
Earnings	**1,441**	847	**4,789**	5,658
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(46)**	(59)	**(115)**	(227)
Earnings attributable to controlling interests	**1,395**	788	**4,674**	5,431
Preference share dividends	**(107)**	(106)	**(319)**	(311)
Earnings attributable to common shareholders	**1,288**	682	**4,355**	5,120
Earnings per common share attributable to common shareholders *(Note 5)*	**0.59**	0.30	**2.00**	2.34
Diluted earnings per common share attributable to common shareholders *(Note 5)*	**0.59**	0.30	**1.99**	2.33

The accompanying notes are an integral part of these interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(unaudited; millions of Canadian dollars)				
Earnings	**1,441**	847	**4,789**	5,658
Other comprehensive income/(loss), net of tax				
Change in unrealized gain/(loss) on cash flow hedges	**119**	(9)	**138**	(23)
Gain/(loss) on net investment hedges *(Note 11)*	**(30)**	(197)	**(525)**	216
Other comprehensive income/(loss) from equity investees and other investments	**(31)**	5	**(48)**	26
Excluded components of fair value hedges	**—**	—	**—**	14
Reclassification to earnings of (gain)/loss on cash flow hedges	**(3)**	8	**103**	22
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**(6)**	(7)	**(18)**	(20)
Reclassification of actuarial gain on pension and OPEB from regulatory assets	**—**	—	**—**	49
Foreign currency translation adjustments	**63**	1,329	**2,546**	(2,086)
Other comprehensive income/(loss), net of tax	**112**	1,129	**2,196**	(1,802)
Comprehensive income	**1,553**	1,976	**6,985**	3,856
Comprehensive income attributable to noncontrolling interests and redeemable noncontrolling interests	**(46)**	(80)	**(147)**	(188)
Comprehensive income attributable to controlling interests	**1,507**	1,896	**6,838**	3,668
Preference share dividends	**(107)**	(106)	**(319)**	(311)
Comprehensive income attributable to common shareholders	**1,400**	1,790	**6,519**	3,357

The accompanying notes are an integral part of these interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(unaudited; millions of Canadian dollars, except per share amounts)				
Preference shares				
Balance at beginning and end of period	**6,818**	6,818	**6,818**	6,818
Common shares				
Balance at beginning of period	**71,949**	71,823	**71,876**	71,738
Shares issued, net of issue costs and tax	**2,915**	—	**2,915**	—
Shares issued on exercise of stock options	**1**	13	**19**	59
Shares issued on vesting of restricted stock units (RSU)	**2**	—	**57**	39
Balance at end of period	**74,867**	71,836	**74,867**	71,836
Additional paid-in capital				
Balance at beginning of period	**183**	226	**242**	275
Stock-based compensation	**25**	25	**86**	85
Stock options exercised	**(1)**	(11)	**(23)**	(51)
Vested RSUs	**(3)**	—	**(101)**	(69)
Balance at end of period	**204**	240	**204**	240
Deficit				
Balance at beginning of period	**(20,334)**	(17,663)	**(21,284)**	(20,046)
Earnings attributable to controlling interests	**1,395**	788	**4,674**	5,431
Preference share dividends	**(107)**	(106)	**(319)**	(311)
Common share dividends declared	**(2,119)**	(2,055)	**(4,239)**	(4,110)
Redemption value adjustment attributable to redeemable noncontrolling interest	**3**	(28)	**6**	(28)
Balance at end of period	**(21,162)**	(19,064)	**(21,162)**	(19,064)
Accumulated other comprehensive income *(Note 10)*				
Balance at beginning of period	**6,733**	4,244	**4,681**	7,115
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**112**	1,108	**2,164**	(1,763)
Balance at end of period	**6,845**	5,352	**6,845**	5,352
Total Enbridge Inc. shareholders' equity	**67,572**	65,182	**67,572**	65,182
Noncontrolling interests				
Balance at beginning of period	**2,760**	2,910	**2,855**	2,993
Earnings attributable to noncontrolling interests	**31**	43	**74**	211
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax				
Change in unrealized loss on cash flow hedges	**—**	—	**(2)**	(1)
Foreign currency translation adjustments	**—**	21	**34**	(38)
	—	21	**32**	(39)
Comprehensive income attributable to noncontrolling interests	**31**	64	**106**	172
Distributions	**(92)**	(81)	**(272)**	(276)
Contributions	**2**	1	**12**	8
Other	**—**	—	**—**	(3)
Balance at end of period	**2,701**	2,894	**2,701**	2,894
Total equity	**70,273**	68,076	**70,273**	68,076
Dividends paid per common share	**0.97**	0.94	**2.91**	2.82

The accompanying notes are an integral part of these interim consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Nine months ended September 30,	
	2026	2025
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**4,789**	5,658
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**4,352**	4,197
Deferred income tax expense	**744**	944
Unrealized derivative fair value loss/(gain), net	**308**	(997)
Income from equity investments	**(1,590)**	(1,690)
Distributions from equity investments	**1,439**	1,547
Impairment of long-lived assets	**—**	330
Other	**77**	(91)
Changes in operating assets and liabilities	**(963)**	(739)
Net cash provided by operating activities	**9,156**	9,159
Investing activities		
Capital expenditures	**(8,856)**	(5,944)
Long-term, restricted and other investments	**(1,077)**	(1,867)
Distributions from equity investments in excess of cumulative earnings	**606**	531
Additions to intangible assets	**(230)**	(215)
Proceeds from disposition of equity investments	**—**	349
Other	**(28)**	(41)
Net cash used in investing activities	**(9,585)**	(7,187)
Financing activities		
Net change in short-term borrowings	**504**	745
Net change in commercial paper and credit facility draws	**2,457**	788
Debenture and term note issues, net of issue costs	**5,717**	8,314
Debenture and term note repayments	**(1,080)**	(6,114)
Contributions from noncontrolling interests	**12**	8
Distributions to noncontrolling interests	**(272)**	(276)
Proceeds from investment by redeemable noncontrolling interest in subsidiary, net of transaction costs	**702**	712
Contributions from redeemable noncontrolling interest	**16**	—
Distributions to redeemable noncontrolling interest	**(52)**	—
Common shares issued, net of issue costs	**2,893**	8
Preference share dividends	**(319)**	(311)
Common share dividends	**(6,355)**	(6,164)
Net change in affiliate loans	**47**	39
Other	**(87)**	(41)
Net cash provided by/(used in) financing activities	**4,183**	(2,292)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**69**	(28)
Net change in cash and cash equivalents and restricted cash	**3,823**	(348)
Cash and cash equivalents and restricted cash at beginning of period[1]	**1,320**	2,000
Cash and cash equivalents and restricted cash at end of period[1]	**5,143**	1,652

The accompanying notes are an integral part of these interim consolidated financial statements.

1 As at September 30, 2026 and December 31, 2025, long-term restricted cash of $147 million (September 30, 2025 - $141 million) and $143 million (December 31, 2024 - $105 million), respectively, was included in Restricted long-term investments and cash in the Consolidated Statements of Financial Position.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2026	December 31, 2025
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**4,898**	1,094
Restricted cash	**98**	83
Trade receivables and unbilled revenues	**8,942**	7,081
Other current assets	**4,839**	3,230
Accounts receivable from affiliates	**97**	86
Inventory	**2,054**	1,621
	20,928	13,195
Property, plant and equipment, net	**140,405**	131,598
Long-term investments	**22,522**	21,264
Restricted long-term investments and cash *(Note 11)*	**1,534**	1,293
Deferred amounts and other assets	**12,160**	11,149
Intangible assets, net	**3,922**	3,991
Goodwill	**36,234**	35,284
Deferred income taxes	**857**	701
Total assets	**238,562**	218,475
Liabilities and equity		
Current liabilities		
Short-term borrowings	**1,534**	1,030
Trade payables and accrued liabilities	**10,139**	7,555
Other current liabilities	**5,481**	6,174
Accounts payable to affiliates	**49**	38
Interest payable	**1,237**	1,176
Current portion of long-term debt	**7,406**	5,031
	25,846	21,004
Long-term debt	**105,343**	98,963
Other long-term liabilities	**13,704**	12,302
Deferred income taxes	**21,963**	20,282
	166,856	152,551
Contingencies *(Note 14)*		
Redeemable noncontrolling interests	**1,433**	736
Equity		
Share capital		
Preference shares	**6,818**	6,818
Common shares *(2,229 and 2,182 outstanding at September 30, 2026 and December 31, 2025, respectively)*	**74,867**	71,876
Additional paid-in capital	**204**	242
Deficit	**(21,162)**	(21,284)
Accumulated other comprehensive income *(Note 10)*	**6,845**	4,681
Total Enbridge Inc. shareholders' equity	**67,572**	62,333
Noncontrolling interests	**2,701**	2,855
	70,273	65,188
Total liabilities and equity	**238,562**	218,475

The accompanying notes are an integral part of these 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 (US GAAP) and Regulation S-X for interim consolidated financial information. They do not include all of the information and notes required by US GAAP for annual consolidated financial statements and should therefore be read in conjunction with our audited consolidated financial statements and notes for the year ended December 31, 2025. 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 consolidated financial statements for the year ended December 31, 2025. 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 supply of and demand for crude oil and natural gas and may not be indicative of annual results.

Certain comparative figures in our interim consolidated financial statements have been reclassified to conform to the current year's presentation.

2. CHANGES IN ACCOUNTING POLICIES

FUTURE ACCOUNTING POLICY CHANGES

Disaggregation of Income Statement Expenses

Accounting Standards Update (ASU) 2024-03 was issued in November 2024 to improve financial reporting by requiring entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods. The ASU requires entities to disclose 1) the amounts of (a) purchases of inventory, (b) employee compensation, (c) depreciation, (d) intangible asset amortization, (e) depreciation, depletion and amortization recognized as part of oil and gas producing activities, (f) expense reimbursements included in a relevant expense caption, and (g) selling expenses, and 2) a qualitative description of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. ASU 2024-03 is effective January 1, 2027, with interim period disclosure requirements effective after January 1, 2028, and can be applied either prospectively or retrospectively. The additional note disclosures will be included in our December 31, 2027 annual consolidated financial statements and in our interim financial statements beginning in 2028.

3. REVENUE

REVENUE FROM CONTRACTS WITH CUSTOMERS
Major Products and Services

Three months ended September 30, 2026	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	**2,772**	**1,435**	**67**	**—**	**—**	**4,274**
Storage and other revenue	**66**	**172**	**130**	**—**	**—**	**368**
Gas distribution sales	**—**	**—**	**1,344**	**—**	**—**	**1,344**
Electricity revenue	**—**	**—**	**—**	**84**	**—**	**84**
Commodity sales	**—**	**40**	**9**	**—**	**—**	**49**
Total revenue from contracts with customers	**2,838**	**1,647**	**1,550**	**84**	**—**	**6,119**
Commodity sales	**14,530**	**59**	**—**	**—**	**213**	**14,802**
Other revenue[1,2]	**52**	**15**	**24**	**65**	**—**	**156**
Intersegment revenue	**—**	**5**	**2**	**2**	**(9)**	**—**
Total revenue	**17,420**	**1,726**	**1,576**	**151**	**204**	**21,077**

Three months ended September 30, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	2,934	1,361	62	—	—	4,357
Storage and other revenue	77	158	119	—	—	354
Gas distribution sales	—	—	1,295	—	—	1,295
Electricity revenue	—	—	—	72	—	72
Commodity sales	—	32	22	—	—	54
Total revenue from contracts with customers	3,011	1,551	1,498	72	—	6,132
Commodity sales	8,101	23	—	—	218	8,342
Other revenue[1,2]	71	20	18	56	—	165
Intersegment revenue	—	3	(3)	2	(2)	—
Total revenue	11,183	1,597	1,513	130	216	14,639

Nine months ended September 30, 2026	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	**8,287**	**4,368**	**203**	**—**	**—**	**12,858**
Storage and other revenue	**194**	**532**	**432**	**—**	**—**	**1,158**
Gas distribution sales	**—**	**—**	**7,287**	**—**	**—**	**7,287**
Electricity revenue	**—**	**—**	**—**	**238**	**—**	**238**
Commodity sales	**—**	**114**	**24**	**—**	**—**	**138**
Total revenue from contracts with customers	**8,481**	**5,014**	**7,946**	**238**	**—**	**21,679**
Commodity sales	**49,430**	**152**	**—**	**—**	**908**	**50,490**
Other revenue[1,2]	**192**	**45**	**100**	**246**	**—**	**583**
Intersegment revenue	**—**	**16**	**19**	**5**	**(40)**	**—**
Total revenue	**58,103**	**5,227**	**8,065**	**489**	**868**	**72,752**

Nine months ended September 30, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Eliminations and Other	Consolidated
(millions of Canadian dollars)						
Transportation revenue	8,934	4,190	187	—	—	13,311
Storage and other revenue	220	493	428	—	—	1,141
Gas distribution sales	—	—	6,696	—	—	6,696
Electricity revenue	—	—	—	166	—	166
Commodity sales	—	84	22	—	—	106
Total revenue from contracts with customers	9,154	4,767	7,333	166	—	21,420
Commodity sales	24,822	89	—	—	1,052	25,963
Other revenue[1,2]	228	45	138	223	—	634
Intersegment revenue	—	15	14	6	(35)	—
Total revenue	34,204	4,916	7,485	395	1,017	48,017

1 Includes realized and unrealized gains and losses from our hedging program which for the three months ended September 30, 2026 were a net $35 million loss (2025 - $13 million gain) and for the nine months ended September 30, 2026 were a net $28 million loss (2025 - $145 million gain).

2 Includes revenues from lease contracts for the three months ended September 30, 2026 and 2025 of $106 million and $116 million, respectively, and for the nine months ended September 30, 2026 and 2025 of $428 million and $415 million, respectively.

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

Contract Balances

	Contract Receivables	Contract Assets	Contract Liabilities
(millions of Canadian dollars)			
Balance as at September 30, 2026	**2,818**	**228**	**2,885**
Balance as at December 31, 2025	3,799	315	2,765

Contract receivables represent the amount of receivables derived from contracts with customers.

Contract assets represent the amount of revenues which have been recognized in advance of payments received for performance obligations we have fulfilled (or have partially fulfilled) and prior to the point in time at which our right to payment is unconditional. Amounts included in contract assets are transferred to accounts receivable when our right to receive 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. Revenues recognized during the three and nine months ended September 30, 2026 included in contract liabilities at the beginning of the period were $118 million and $445 million, respectively. Increases in contract liabilities from cash received, net of amounts recognized as revenues, during the three and nine months ended September 30, 2026 were $245 million and $496 million, respectively.

Performance Obligations

There were no material revenues recognized in the three and nine months ended September 30, 2026 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 are $56.4 billion, of which $2.6 billion and $8.9 billion are expected to be recognized during the remaining three months ending December 31, 2026 and the year ending December 31, 2027, respectively.

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

Recognition and Measurement of Revenues

Three months ended September 30, 2026	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	**—**	**40**	**38**	**15**	**93**
Revenues from products and services transferred over time[1]	**2,838**	**1,607**	**1,512**	**69**	**6,026**
Total revenue from contracts with customers	**2,838**	**1,647**	**1,550**	**84**	**6,119**

Three months ended September 30, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	—	32	42	22	96
Revenues from products and services transferred over time[1]	3,011	1,519	1,456	50	6,036
Total revenue from contracts with customers	3,011	1,551	1,498	72	6,132

Nine months ended September 30, 2026	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	**—**	**114**	**130**	**48**	**292**
Revenues from products and services transferred over time[1]	**8,481**	**4,900**	**7,816**	**190**	**21,387**
Total revenue from contracts with customers	**8,481**	**5,014**	**7,946**	**238**	**21,679**

Nine months ended September 30, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	—	84	109	38	231
Revenues from products and services transferred over time[1]	9,154	4,683	7,224	128	21,189
Total revenue from contracts with customers	9,154	4,767	7,333	166	21,420

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

4. SEGMENTED INFORMATION

Three months ended September 30, 2026	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage[1]	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[2]	**17,420**	**1,726**	**1,576**	**151**	**20,873**
Commodity and gas distribution costs	**(14,484)**	**(44)**	**(268)**	**—**	**(14,796)**
Operating and administrative	**(1,085)**	**(566)**	**(708)**	**(95)**	**(2,454)**
Income from equity investments	**234**	**248**	**4**	**36**	**522**
Other income	**48**	**94**	**61**	**21**	**224**
Earnings before interest, income taxes and depreciation and amortization	**2,133**	**1,458**	**665**	**113**	**4,369**
Eliminations and Other					**49**
Depreciation and amortization					**(1,490)**
Interest expense					**(1,049)**
Earnings before income taxes					**1,879**

Three months ended September 30, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage[1]	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[2]	11,183	1,597	1,513	130	14,423
Commodity and gas distribution costs	(8,032)	(12)	(284)	(2)	(8,330)
Operating and administrative	(1,108)	(571)	(719)	(87)	(2,485)
Income from equity investments	230	192	1	32	455
Other income	10	64	49	16	139
Earnings before interest, income taxes and depreciation and amortization	2,283	1,270	560	89	4,202
Eliminations and Other					(379)
Depreciation and amortization					(1,398)
Interest expense					(1,262)
Earnings before income taxes					1,163

Nine months ended September 30, 2026	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage[1]	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[2]	**58,103**	**5,227**	**8,065**	**489**	**71,884**
Commodity and gas distribution costs	**(49,031)**	**(96)**	**(2,792)**	**—**	**(51,919)**
Operating and administrative	**(3,177)**	**(1,681)**	**(2,192)**	**(268)**	**(7,318)**
Income from equity investments	**742**	**707**	**4**	**149**	**1,602**
Other income	**76**	**304**	**167**	**49**	**596**
Earnings before interest, income taxes and depreciation and amortization	**6,713**	**4,461**	**3,252**	**419**	**14,845**
Eliminations and Other					**(571)**
Depreciation and amortization					**(4,352)**
Interest expense					**(3,666)**
Earnings before income taxes					**6,256**

Nine months ended September 30, 2025	Liquids Pipelines	Gas Transmission	Gas Distribution and Storage[1]	Renewable Power Generation	Total Reportable Segments
(millions of Canadian dollars)					
Operating revenues[2]	34,204	4,916	7,485	395	47,000
Commodity and gas distribution costs	(24,623)	(39)	(2,471)	2	(27,131)
Operating and administrative	(3,268)	(1,609)	(2,179)	(237)	(7,293)
Impairment of long-lived assets[3]	—	—	(330)	—	(330)
Income from equity investments	843	665	2	191	1,701
Other income	51	252	163	70	536
Earnings before interest, income taxes and depreciation and amortization	7,207	4,185	2,670	421	14,483
Eliminations and Other					828
Depreciation and amortization					(4,197)
Interest expense					(3,777)
Earnings before income taxes					7,337

1 Primarily relates to public utilities that are subject to regulation.

2 Refer to Note 3 - Revenue *for a reconciliation of segment Operating revenues to the Consolidated Statements of Earnings.*

3 The Gas Distribution and Storage segment includes the impact of an impairment recognized for certain rate-regulated assets related to pension and other disallowances as a result of the Public Utilities Commission of Ohio's June 2025 order related to Enbridge Gas Ohio's rate case.

Capital Expenditures[1]

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Liquids Pipelines	**661**	307	**1,515**	900
Gas Transmission	**1,175**	933	**3,555**	2,228
Gas Distribution and Storage	**880**	914	**2,336**	2,310
Renewable Power Generation	**801**	173	**1,634**	532
Eliminations and Other	**—**	20	**—**	71
	3,517	2,347	**9,040**	6,041

1 Capital expenditures are cash basis plus equity component of the allowance for funds used during construction.

Property, Plant and Equipment

	September 30, 2026	December 31, 2025
(millions of Canadian dollars)		
Liquids Pipelines	**53,085**	51,689
Gas Transmission	**39,178**	35,421
Gas Distribution and Storage	**41,512**	39,644
Renewable Power Generation	**6,291**	4,439
Eliminations and Other	**339**	405
	140,405	131,598

5. EARNINGS PER COMMON SHARE AND DIVIDENDS PER SHARE

NUMERATOR

The numerator used in calculating both basic and diluted earnings per share equals Earnings attributable to common shareholders per the Consolidated Statements of Earnings, including the Redemption value adjustment attributable to Redeemable noncontrolling interests (NCI) per the Consolidated Statements of Changes in Equity.

DENOMINATOR

The denominator of the basic earnings per common share calculation represents the weighted average number of common shares outstanding.

The denominator of the diluted earnings per common share calculation uses the treasury stock method to determine the dilutive impact of stock options and share-settled RSUs. This method assumes any proceeds from the exercise of stock options and vesting of share-settled RSUs would be used to purchase common shares at the average market price during the period. The basic weighted average shares outstanding are adjusted by this dilutive impact to derive the diluted weighted average shares outstanding.

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

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(number of shares in millions)				
Weighted average shares outstanding	**2,192**	2,181	**2,186**	2,180
Effect of dilutive options and RSUs	**6**	6	**6**	6
Diluted weighted average shares outstanding	**2,198**	2,187	**2,192**	2,186

For the three months ended September 30, 2026, 2.3 million anti-dilutive stock options with a weighted average exercise price of $70.49 were excluded from the diluted earnings per common share calculation. There were no anti-dilutive stock options outstanding for the three months ended September 30, 2025.

For the nine months ended September 30, 2026 and 2025, 1.5 million and 1.6 million, respectively, anti-dilutive stock options with a weighted average exercise price of $70.12 and $60.37, respectively, were excluded from the diluted earnings per common share calculation.

DIVIDENDS PER SHARE

On November 3, 2026, our Board of Directors declared the following quarterly dividends. All dividends are payable on December 1, 2026 to shareholders of record on November 13, 2026.

	Dividend per share
Common Shares	$0.9700
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.32513
Preference Shares, Series D	$0.33825
Preference Shares, Series F	$0.34613
Preference Shares, Series G[1]	$0.29918
Preference Shares, Series H	$0.38200
Preference Shares, Series I[2]	$0.27487
Preference Shares, Series L	US$0.36612
Preference Shares, Series N	$0.41850
Preference Shares, Series P	$0.36988
Preference Shares, Series R	$0.39463
Preference Shares, Series 1	US$0.41898
Preference Shares, Series 3	$0.33050
Preference Shares, Series 4[3]	$0.29108
Preference Shares, Series 5	US$0.41769
Preference Shares, Series 7	$0.37425
Preference Shares, Series 9	$0.35450
Preference Shares, Series 11	$0.34231
Preference Shares, Series 13	$0.33719
Preference Shares, Series 15	$0.35163
Preference Shares, Series 19	$0.38825

1 The quarterly dividend per share paid on Preference Shares, Series G was decreased to $0.29918 from $0.30247 on September 1, 2026 due to the reset of the dividend on a quarterly basis.

2 The quarterly dividend per share paid on Preference Shares, Series I was decreased to $0.27487 from $0.27789 on September 1, 2026 due to the reset of the dividend on a quarterly basis.

3 The quarterly dividend per share paid on Preference Shares, Series 4 was decreased to $0.29108 from $0.29427 on September 1, 2026 due to the reset of the dividend on a quarterly basis.

6. ACQUISITION AND DISPOSITIONS

BUSINESS COMBINATIONS

We account for acquisitions using the acquisition method as prescribed by ASC 805 *Business Combinations*. In accordance with valuation methodologies described in ASC 820 *Fair Value Measurement*, acquired assets and assumed liabilities are recorded at their estimated fair values as at the date of acquisition.

Salt Creek Midstream Crude Acquisition

On October 9, 2026, through a wholly-owned subsidiary, we acquired from Salt Creek Midstream (Salt Creek) all of the membership interests of FS Crude Holdings, LLC (FS Crude) for total cash consideration of approximately $892 million (US$625 million) (the Salt Creek Crude Acquisition). FS Crude owns 100% of the Orla and Wink North systems and 50% of the Delaware Crossing system, which combined include approximately 500 miles of crude oil gathering infrastructure located in the Delaware Basin. The Salt Creek Crude Acquisition is expected to strengthen our crude oil value chain in the Permian Basin by providing a strategic connection between crude oil production and our Gray Oak and Cactus II Pipeline systems, as well as our Enbridge Ingleside Energy Center.

The purchase price for the Salt Creek Crude Acquisition was preliminarily allocated to the assets acquired and liabilities assumed based on their estimated fair values at acquisition date. The acquisition resulted in the recognition of approximately $0.6 billion of Property, plant and equipment and $0.3 billion of other net assets acquired.

FS Crude's property, plant and equipment constitute crude oil gathering systems, comprised of pipelines, a terminal, land and right-of-ways. The depreciated replacement cost approach was adopted as the primary valuation methodology to determine the fair value of property, plant and equipment. In determining replacement cost, both indirect costing using relevant inflation indices and direct costing using relevant market quotes were utilized.

The purchase price allocation for the Salt Creek Crude Acquisition was prepared on a preliminary basis and is subject to change as additional information becomes available regarding the fair values and tax bases of assets and liabilities acquired. Any adjustments to the purchase price allocation will be made as soon as practicable, but no later than one year from the date of acquisition.

Common Share Issuance

On September 14, 2026, we closed a public offering of 44,735,000 common shares of Enbridge at a price of $66.85 per share for gross proceeds of $3.0 billion. Net proceeds from the sale of common shares were used to partially fund the Salt Creek Crude Acquisition, with the remaining proceeds available to fund future growth opportunities.

REDEEMABLE NONCONTROLLING INTEREST INVESTMENTS

Westcoast Expansion Financing Limited Partnership

On July 30, 2026, Westcoast Energy LP Inc. (WELP), our wholly-owned subsidiary, transferred certain of its non-participating Class C units in Westcoast Energy Limited Partnership (Westcoast LP) to a newly formed limited partnership, Westcoast Expansion Financing Limited Partnership (Westcoast Expansion), in exchange for Class I and Class II units. The remaining Class C units were retained by WELP to meet our obligations to Stonlasec8 Indigenous Investments Limited Partnership (the First Nations Partnership), an entity representing 38 First Nations in British Columbia (BC), under the Class C purchase option.

The Class C unitholders fund designated capital programs within Westcoast LP, which owns and operates our Westcoast Energy Inc. (Westcoast) BC Pipeline system. Westcoast Expansion has committed to invest in our Aspen Point and Sunrise Expansion Programs (the Expansions) in exchange for additional non-participating Class C units in Westcoast LP.

On September 3, 2026, KKR & Co. Inc. (KKR), in collaboration with funds and affiliates managed by Apollo, invested $729 million for all of the Class II units of Westcoast Expansion, resulting in an interest in the partnership. In addition to the initial cash consideration, KKR has committed to contribute approximately $2.0 billion to fund the Expansions in exchange for additional Class II units.

The cash consideration of $729 million and a respective redeemable NCI based on the consideration received less transaction costs were recorded in the Consolidated Statements of Financial Position on close, to reflect the interest held by KKR in Westcoast Expansion. Refer to *Note 7 - Variable Interest Entities* and *Note 9 - Redeemable Noncontrolling Interests.*

Westcoast Energy Limited Partnership
On July 1, 2025, Westcoast completed a reorganization in which substantially all of the property and assets relating to the BC Pipeline system were transferred to a newly formed partnership, Westcoast LP. On July 2, 2025, the First Nations Partnership invested approximately $736 million to subscribe for all of the Class A units of Westcoast LP, resulting in a 12.50% interest in the partnership. The cash consideration of $736 million and a respective redeemable NCI based on the consideration received less transaction costs were recorded in the Consolidated Statements of Financial Position on close, to reflect the interest held by the First Nations Partnership.

Following the transactions discussed above, we continue to manage and operate the BC Pipeline system through our ownership interest in Westcoast LP. Refer to *Note 9 - Redeemable Noncontrolling Interests*.

7. VARIABLE INTEREST ENTITIES

CONSOLIDATED VARIABLE INTEREST ENTITIES
Our consolidated variable interest entities (VIEs) consist of legal entities of which we are the primary beneficiary. We are the primary beneficiary when our variable interest(s) provide(s) us with (i) the power to direct the activities of the VIE that most significantly impact the entity's economic performance and (ii) the obligation to absorb losses, or the right to receive benefits, from the VIE that could potentially be significant to the VIE. We determine whether we are the primary beneficiary of a VIE by considering qualitative and quantitative factors, including, but not limited to: decision-making responsibilities, the VIE capital structure, risk and reward sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties.

Westcoast Expansion Financing Limited Partnership
Westcoast Expansion is a BC limited partnership which holds an ownership interest in Westcoast LP for the purpose of funding construction costs associated with the Expansions. The limited partners, WELP and Tuscan Issuer Ltd. (an affiliate of KKR), hold 19.99% and 80.0% interests in Westcoast Expansion, respectively. The remaining 0.01% general partner interest is held by Westcoast Expansion Financing GP Inc., our wholly-owned subsidiary.

Westcoast Expansion is considered a VIE as it does not have sufficient equity at risk to finance its activities without additional subordinated financial support and its limited partners lack substantive participating rights and kick-out rights. In addition to having the obligation to absorb losses and the right to expected returns, we, through WELP's direct interests and the provisions of the limited partnership agreement, have the ability to direct the activities of Westcoast Expansion's principal operations, thereby making us the primary beneficiary of the VIE. Westcoast Expansion is a consolidated VIE of Enbridge.

The assets of Westcoast Expansion primarily consist of its investment in Westcoast LP, which eliminates upon Enbridge's consolidation. We did not provide any additional financial support to Westcoast Expansion during the period ended September 30, 2026.

8. DEBT

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at September 30, 2026:

	Maturity[1]	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2028-2049	**8,046**	**6,883**	**1,163**
Enbridge (U.S.) Inc.	2027-2031	**10,675**	**5,895**	**4,780**
Enbridge Pipelines Inc.	2028	**2,000**	**1,996**	**4**
Enbridge Gas Inc.	2028	**2,500**	**1,535**	**965**
Total committed credit facilities		**23,221**	**16,309**	**6,912**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

In July 2026, we renewed our 364-day extendible credit facilities, extending the maturity dates to July 2028, which includes a one-year term out provision from July 2027. We also renewed our five-year credit facilities, extending the maturity dates to July 2031. Further, we extended the maturity dates of our three-year credit facilities to July 2029.

In addition to the committed credit facilities noted above, we maintain $1.5 billion of uncommitted demand letter of credit facilities, of which $776 million was unutilized as at September 30, 2026. As at December 31, 2025, we had $1.6 billion of uncommitted demand letter of credit facilities, of which $932 million was 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 our commercial paper programs and we have the option to extend such facilities, which are currently scheduled to mature from 2027 to 2049.

As at September 30, 2026 and December 31, 2025, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $14.8 billion and $12.1 billion, respectively, were supported by the availability of long-term committed credit facilities and, therefore, have been classified as long-term debt.

LONG-TERM DEBT ISSUANCES

During the nine months ended September 30, 2026, we completed the following long-term debt issuances totaling $3.0 billion and US$2.0 billion:

Company	Issuance Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	February 2026	3.57%	medium term notes due February 2031	$850
	February 2026	4.35%	medium term notes due February 2036	$850
	February 2026	5.10%	medium term notes due February 2056	$300
	March 2026	4.85%	senior notes due March 2031	US$1,000
	March 2026	5.45%	senior notes due March 2036	US$1,000
Enbridge Gas Inc.				
	August 2026	4.65%	medium term notes due August 2036	$600
	August 2026	5.35%	medium term notes due August 2056	$400

In October 2026, Public Service Company of North Carolina, Incorporated closed a two-tranche offering consisting of ten-year and thirty-year senior notes for an aggregate principal amount of US$500 million which mature in October 2036 and October 2056, respectively.

LONG-TERM DEBT REPAYMENTS

During the nine months ended September 30, 2026, we completed the following long-term debt repayments totaling $955 million, US$64 million and €22 million:

Company	Repayment Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Gas Inc.				
	June 2026	2.81%	medium term notes	$250
	August 2026	2.50%	medium term notes	$300
Enbridge Pipelines (Southern Lights) L.L.C.				
	June 2026	3.98%	senior notes	US$14
Enbridge Pipelines Inc.				
	May 2026	3.00%	medium term notes[1]	$400
Enbridge Southern Lights LP				
	June 2026	4.01%	senior notes	$5
Blauracke GmbH				
	April 2026	2.10%	senior notes	€22
Public Service Company of North Carolina, Incorporated				
	January 2026	6.99%	debentures	US$50

1 The notes carried an original maturity date of August 2026.

SUBORDINATED TERM NOTES

As at September 30, 2026 and December 31, 2025, our fixed-to-floating rate and fixed-to-fixed rate subordinated term notes had an aggregate principal value of $16.4 billion and $16.0 billion, respectively.

FAIR VALUE ADJUSTMENT

As at September 30, 2026 and December 31, 2025, the fair value adjustments to decrease total debt assumed in historical acquisitions were $447 million and $430 million, respectively.

DEBT COVENANTS

Our credit facility agreements and term debt trust indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at September 30, 2026, we were in compliance with all such debt covenant provisions.

9. REDEEMABLE NONCONTROLLING INTERESTS

The following table provides additional information regarding Redeemable NCI as presented in our Consolidated Statements of Financial Position:

	September 30, 2026	December 31, 2025
(millions of Canadian dollars)		
Westcoast Expansion Financing Limited Partnership[1]	**697**	—
Westcoast Energy Limited Partnership[2]	**736**	736
	1,433	736

1 Represents the Class II units held by KKR.
2 Represents the Class A units held by the First Nations Partnership.

The changes in our Redeemable NCI were as follows:

Nine months ended September 30,	**2026**	2025
(millions of Canadian dollars)		
Class A units		
Balance at beginning of period	**736**	—
Proceeds from investment by redeemable noncontrolling interest in subsidiary	**—**	736
Transaction costs, net of tax benefit	**—**	(27)
Earnings attributable to redeemable noncontrolling interest	**41**	16
Distributions declared to unitholder	**(51)**	(17)
Contributions from unitholder	**16**	—
Redemption value adjustment	**(6)**	28
	736	736
Class II units		
Balance at beginning of period	**—**	—
Proceeds from investment by redeemable noncontrolling interest in subsidiary	**729**	—
Transaction costs, net of tax benefit	**(22)**	—
Other	**(10)**	—
	697	—
Balance at end of period	**1,433**	736

Westcoast Expansion Financing Limited Partnership
In addition to funding the Expansions, Westcoast Expansion has committed to make contributions to Westcoast LP for capital costs for other than designated capital programs in exchange for Class B units. These contributions would be funded by WELP and KKR through additional investments in Westcoast Expansion in exchange for additional Class I and Class II units, respectively.

The Class II units entitle KKR to receive contingently required distributions if certain events occur, including delays in the Expansions commencing commercial operations, force majeure and regulatory disallowances. WELP may also repurchase KKR's Class II units under certain circumstances or during designated call periods, with the repurchase price determined in accordance with the terms of the limited partnership agreement.

As a result of these contingently required distributions, we have classified KKR's Class II units as Redeemable NCI within the mezzanine equity section of the Consolidated Statements of Financial Position. As at September 30, 2026, the Redeemable NCI was recognized at its carrying value as redemption is not probable.

Westcoast Energy Limited Partnership
As at September 30, 2026, the First Nations Partnership held a 12.58% redeemable noncontrolling interest in Westcoast LP, which increased from 12.47% as at December 31, 2025 as a result of their minimum required contribution amount exceeding their pro-rata share of total capital costs for other than designated capital programs.

10. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated other comprehensive income (AOCI) attributable to our common shareholders for the nine months ended September 30, 2026 and 2025 are as follows:

	Cash Flow Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees and Other Investments	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)						
Balance as at January 1, 2026	**462**	**(1,614)**	**5,372**	**25**	**436**	**4,681**
Other comprehensive income/(loss) retained in AOCI	**184**	**(525)**	**2,512**	**(27)**	**—**	**2,144**
Other comprehensive (income)/loss reclassified to earnings						
Interest rate contracts[1]	**137**	**—**	**—**	**—**	**—**	**137**
Amortization of pension and OPEB actuarial gain[2]	**—**	**—**	**—**	**—**	**(27)**	**(27)**
	321	**(525)**	**2,512**	**(27)**	**(27)**	**2,254**
Tax impact						
Income tax on amounts retained in AOCI	**(44)**	**—**	**—**	**(21)**	**—**	**(65)**
Income tax on amounts reclassified to earnings	**(34)**	**—**	**—**	**—**	**9**	**(25)**
	(78)	**—**	**—**	**(21)**	**9**	**(90)**
Balance as at September 30, 2026	**705**	**(2,139)**	**7,884**	**(23)**	**418**	**6,845**

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees and Other Investments	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2025	407	(14)	(2,033)	8,452	1	302	7,115
Other comprehensive income/(loss) retained in AOCI	(22)	12	216	(2,048)	26	62	(1,754)
Other comprehensive (income)/loss reclassified to earnings							
Interest rate contracts[1]	26	—	—	—	—	—	26
Foreign exchange contracts[3]	—	(3)	—	—	—	—	(3)
Amortization of pension and OPEB actuarial gain[2]	—	—	—	—	—	(24)	(24)
	4	9	216	(2,048)	26	38	(1,755)
Tax impact							
Income tax on amounts retained in AOCI	—	4	—	—	—	(13)	(9)
Income tax on amounts reclassified to earnings	(4)	1	—	—	—	4	1
	(4)	5	—	—	—	(9)	(8)
Balance as at September 30, 2025	407	—	(1,817)	6,404	27	331	5,352

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

2 These components are included in the computation of net periodic benefit credit and are reported within Other income/(expense) in the Consolidated Statements of Earnings.

3 Reported within Interest expense and Other income/(expense) in the Consolidated Statements of Earnings.

11. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK
Our earnings, cash flows and other comprehensive income/(loss) (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 US dollar-denominated investments and subsidiaries using US 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. We have a policy of limiting the maximum floating rate debt to 30% of total debt outstanding. We monitor and adjust our debt portfolio mix of fixed and variable rate debt instruments along with the use of derivative instruments, to support compliance with our policy. We have implemented a program to partially mitigate the impact of short-term interest rate volatility on interest expense via the execution of floating-to-fixed interest rate swaps and costless collars. These swaps have an average fixed rate of 3.1%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of 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 fair value. Executed fixed-to-floating interest rate swaps have an average swap rate of 3.5%.

Our earnings, cash flows and OCI are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. A combination of qualifying and non-qualifying forward starting interest rate swaps is used to hedge against the effect of future interest rate movements. We have established a program including some of our subsidiaries to partially mitigate our exposure to long-term interest rate variability on forecasted term debt issuances via execution of floating-to-fixed interest rate swaps with an average swap rate of 3.7%.

Commodity Price Risk
Our earnings, cash flows and OCI 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 marketing subsidiaries. These commodities include natural gas, crude oil, power and natural gas liquids (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. For our US Gas Utilities, changes in derivatives' fair values are deferred as regulatory assets or liabilities until settlement. 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 the revaluation of outstanding units every period.

TOTAL DERIVATIVE INSTRUMENTS

We have a policy of entering into individual International Swaps and Derivatives Association, Inc. (ISDA) 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 in those circumstances.

The following tables summarize the Consolidated Statements of Financial Position location and carrying value of our derivative instruments, as well as the maximum potential settlement amounts, in the event of the specific circumstances described above.

September 30, 2026	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Other current assets						
Foreign exchange contracts	**—**	**—**	**81**	**81**	**(52)**	**29**
Interest rate contracts	**112**	**15**	**60**	**187**	**(28)**	**159**
Commodity contracts	**—**	**—**	**1,139**	**1,139**	**(818)**	**321**
	112	**15**	**1,280**	**1,407**	**(898)**	**509**
Deferred amounts and other assets						
Foreign exchange contracts	**—**	**—**	**28**	**28**	**(25)**	**3**
Interest rate contracts	**68**	**—**	**623**	**691**	**(635)**	**56**
Commodity contracts	**—**	**—**	**141**	**141**	**(64)**	**77**
	68	**—**	**792**	**860**	**(724)**	**136**
Other current liabilities						
Foreign exchange contracts	**—**	**—**	**(664)**	**(664)**	**52**	**(612)**
Interest rate contracts	**—**	**(9)**	**(21)**	**(30)**	**28**	**(2)**
Commodity contracts	**—**	**—**	**(1,119)**	**(1,119)**	**818**	**(301)**
	—	**(9)**	**(1,804)**	**(1,813)**	**898**	**(915)**
Other long-term liabilities						
Foreign exchange contracts	**—**	**—**	**(1,061)**	**(1,061)**	**25**	**(1,036)**
Interest rate contracts	**—**	**(632)**	**(313)**	**(945)**	**635**	**(310)**
Commodity contracts	**—**	**—**	**(126)**	**(126)**	**64**	**(62)**
	—	**(632)**	**(1,500)**	**(2,132)**	**724**	**(1,408)**
Total net derivative asset/(liability)						
Foreign exchange contracts	**—**	**—**	**(1,616)**	**(1,616)**	**—**	**(1,616)**
Interest rate contracts	**180**	**(626)**	**349**	**(97)**	**—**	**(97)**
Commodity contracts	**—**	**—**	**35**	**35**	**—**	**35**
	180	**(626)**	**(1,232)**	**(1,678)**	**—**	**(1,678)**

December 31, 2025	Derivative Instruments Used as Cash Flow Hedges	Derivative Instruments Used as Fair Value Hedges	Non-Qualifying Derivative Instruments	Total Gross Derivative Instruments as Presented	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)						
Other current assets						
Foreign exchange contracts	—	—	27	27	(17)	10
Interest rate contracts	79	5	22	106	(37)	69
Commodity contracts	—	—	458	458	(192)	266
	79	5	507	591	(246)	345
Deferred amounts and other assets						
Foreign exchange contracts	—	—	52	52	(24)	28
Interest rate contracts	9	—	108	117	(27)	90
Commodity contracts	—	—	124	124	(20)	104
	9	—	284	293	(71)	222
Other current liabilities						
Foreign exchange contracts	—	—	(364)	(364)	17	(347)
Interest rate contracts	(9)	—	(39)	(48)	37	(11)
Commodity contracts	—	—	(300)	(300)	192	(108)
	(9)	—	(703)	(712)	246	(466)
Other long-term liabilities						
Foreign exchange contracts	—	—	(819)	(819)	24	(795)
Interest rate contracts	—	(34)	(50)	(84)	27	(57)
Commodity contracts	—	—	(92)	(92)	20	(72)
	—	(34)	(961)	(995)	71	(924)
Total net derivative asset/(liability)						
Foreign exchange contracts	—	—	(1,104)	(1,104)	—	(1,104)
Interest rate contracts	79	(29)	41	91	—	91
Commodity contracts	—	—	190	190	—	190
	79	(29)	(873)	(823)	—	(823)

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

September 30, 2026	2026	2027	2028	2029	2030	Thereafter	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**3,125**	**—**	**—**	**—**	**—**	**—**	**3,125**
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**2,428**	**5,836**	**4,572**	**2,838**	**1,590**	**498**	**17,762**
Foreign exchange contracts - US dollar collars - sell *(millions of US dollars)*	**45**	**360**	**240**	**120**	**—**	**—**	**765**
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**7**	**32**	**—**	**—**	**—**	**—**	**39**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**29**	**81**	**67**	**66**	**65**	**64**	**372**
Interest rate contracts - short-term pay fixed rate *(millions of Canadian dollars)*	**2,521**	**8,997**	**8,369**	**7,147**	**6,055**	**2,682**	**35,771**
Interest rate contracts - receive fixed rate *(millions of Canadian dollars)*	**2,248**	**8,944**	**8,942**	**8,945**	**8,944**	**69,452**	**107,475**
Interest rate contracts - long-term pay fixed rate *(millions of Canadian dollars)*[1]	**1,136**	**941**	**—**	**—**	**—**	**—**	**2,077**
Interest rate contracts - costless collar *(millions of Canadian dollars)*	**509**	**1,883**	**80**	**—**	**—**	**—**	**2,472**
Commodity contracts - natural gas *(billions of cubic feet)*[2]	**54**	**152**	**41**	**16**	**6**	**—**	**269**
Commodity contracts - crude oil *(millions of barrels)*[2]	**(28)**	**(50)**	**(1)**	**1**	**1**	**—**	**(77)**
Commodity contracts - power *(megawatt per hour (MW/H))*	**146**	**85**	**55**	**29**	**(2)**	**(2)**	**24**[3]

1 Represents the notional amount of long-term debt issuances hedged.
2 Represents the notional amount of net purchase/(sale).
3 Total is an average net purchase/(sale) of power.

Derivatives Designated as Fair Value Hedges

The following table presents interest rate and foreign exchange derivative instruments that are designated and qualify as fair value hedges. The realized and unrealized gain or loss on the derivative is included in Other income/(expense) or Interest expense in the Consolidated Statements of Earnings. The offsetting loss or gain on the hedged item attributable to the hedged risk is included in Other income/(expense) or Interest expense in the Consolidated Statements of Earnings. Any excluded components are included in the Consolidated Statements of Comprehensive Income.

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Unrealized gain/(loss) on derivative	**(558)**	1	**(597)**	(13)
Unrealized gain/(loss) on hedged item	**560**	(1)	**599**	(2)
Realized gain on derivative	**13**	—	**29**	25
Realized loss on hedged item	**(13)**	—	**(29)**	(23)

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Interest rate contracts	**156**	(8)	**182**	(22)
Commodity contracts	**—**	1	**—**	(1)
Fair value hedges				
Foreign exchange contracts	**—**	—	**—**	12
	156	(7)	**182**	(11)
Amount of (income)/loss reclassified from AOCI to earnings				
Foreign exchange contracts[1]	**—**	—	**—**	(3)
Interest rate contracts[2]	**(5)**	9	**137**	26
	(5)	9	**137**	23

1 Reported within Interest expense and Other income/(expense) in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.

We estimate that a gain of $11 million from AOCI related to open 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 two years as at September 30, 2026.

Non-Qualifying Derivatives

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

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**121**	(467)	**(512)**	766
Interest rate contracts[2]	**246**	(8)	**308**	(48)
Commodity contracts[3]	**(276)**	205	**(147)**	331
Other contracts[4]	**—**	—	**—**	(3)
Total unrealized derivative fair value gain/(loss), net	**91**	(270)	**(351)**	1,046

1 Reported within Other income/(expense) in the Consolidated Statements of Earnings.

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

3 For the respective nine months ended periods, reported within Transportation and other services revenues (2026 - $28 million loss; 2025 - $101 million gain), Commodity sales (2026 - $263 million gain; 2025 - $46 million loss), Commodity costs (2026 - $331 million loss; 2025 - $206 million gain) and Operating and administrative expense (2026 - $8 million loss; 2025 - $21 million gain) in the Consolidated Statements of Earnings. The fair value change in our US Gas Utilities is deferred as regulatory assets/(liabilities) (2026 - $43 million loss; 2025 - $49 million gain).

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. 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 medium-term notes. Our shelf prospectuses with securities regulators enable ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain significant liquidity through committed credit facilities with a diversified group of banks and institutions which enables us to fund all anticipated requirements through extended periods of market disruptions without accessing the capital markets. We were in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at September 30, 2026. As a result, all credit facilities are available to us and the banks are obligated to fund us under the terms of the facilities. We also identify other potential sources of debt and equity funding alternatives, including reinstatement of our dividend reinvestment and share purchase plan or at-the-market equity issuances.

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 the maintenance and monitoring of credit exposure limits, contractual requirements and netting arrangements. We also review counterparty financial strength using external credit rating services and other analytical tools to manage credit risk.

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

	September 30, 2026	December 31, 2025
(millions of Canadian dollars)		
Canadian financial institutions	**415**	200
US financial institutions	**904**	260
European financial institutions	**206**	57
Asian financial institutions	**208**	39
Other[1]	**503**	302
	2,236	858

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

As at September 30, 2026, we did not provide any letters of credit in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant ISDA agreements. We held no cash collateral on derivative asset exposures as at September 30, 2026 and December 31, 2025.

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, the assessment of counterparty credit ratings and netting arrangements. Within the Gas Distribution and Storage segment, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover expected credit losses 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 utilize a loss allowance matrix which contemplates historical credit losses by age of receivables, adjusted for any forward-looking information and management expectations to measure lifetime expected credit losses of receivables. 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 derivatives and other financial 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 financial 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 financial instruments 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 financial instrument is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. Under the fair value hierarchy, cash and cash equivalents are classified as Level 1. Our Level 1 instruments consist primarily of exchange-traded derivatives used to mitigate the risk of crude oil price fluctuations and US and Canadian treasury bills. We also hold restricted long-term investments in exchange-traded funds and common shares in trusts in accordance with the regulatory requirements of the Canada Energy Regulator (CER) under the Land Matters Consultation Initiative (LMCI), to cover future pipeline decommissioning costs in the state of Minnesota and to satisfy retirement obligations as Wexpro Company (Wexpro) properties are abandoned.

Level 2
Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Financial instruments 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 financial instrument. 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 long-term debt, investments in debt securities held by our captive insurance subsidiary, and restricted long-term investments in Canadian government bonds held in trust in accordance with the CER's regulatory requirements under the LMCI as Level 2. The fair value of our long-term debt is based on quoted market prices for instruments of similar credit risk and tenor. When possible, the fair value of our restricted long-term investments is based on quoted market prices for similar instruments and, if not available, based on broker quotes.

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 derivative's 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 the extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power, NGL and natural gas contracts, basis swaps, commodity swaps, and power and energy swaps, physical forward commodity contracts, 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.

Fair Value of Derivatives

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

September 30, 2026	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**81**	**—**	**81**
Interest rate contracts	**—**	**187**	**—**	**187**
Commodity contracts	**444**	**67**	**628**	**1,139**
	444	**335**	**628**	**1,407**
Long-term derivative assets				
Foreign exchange contracts	**—**	**28**	**—**	**28**
Interest rate contracts	**—**	**691**	**—**	**691**
Commodity contracts	**33**	**5**	**103**	**141**
	33	**724**	**103**	**860**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(664)**	**—**	**(664)**
Interest rate contracts	**—**	**(30)**	**—**	**(30)**
Commodity contracts	**(575)**	**(69)**	**(475)**	**(1,119)**
	(575)	**(763)**	**(475)**	**(1,813)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(1,061)**	**—**	**(1,061)**
Interest rate contracts	**—**	**(945)**	**—**	**(945)**
Commodity contracts	**(43)**	**(12)**	**(71)**	**(126)**
	(43)	**(2,018)**	**(71)**	**(2,132)**
Total net financial asset/(liability)				
Foreign exchange contracts	**—**	**(1,616)**	**—**	**(1,616)**
Interest rate contracts	**—**	**(97)**	**—**	**(97)**
Commodity contracts	**(141)**	**(9)**	**185**	**35**
	(141)	**(1,722)**	**185**	**(1,678)**

December 31, 2025	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	27	—	27
Interest rate contracts	—	106	—	106
Commodity contracts	70	59	329	458
	70	192	329	591
Long-term derivative assets				
Foreign exchange contracts	—	52	—	52
Interest rate contracts	—	117	—	117
Commodity contracts	—	7	117	124
	—	176	117	293
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(364)	—	(364)
Interest rate contracts	—	(48)	—	(48)
Commodity contracts	(55)	(68)	(177)	(300)
	(55)	(480)	(177)	(712)
Long-term derivative liabilities				
Foreign exchange contracts	—	(819)	—	(819)
Interest rate contracts	—	(84)	—	(84)
Commodity contracts	—	(11)	(81)	(92)
	—	(914)	(81)	(995)
Total net financial asset/(liability)				
Foreign exchange contracts	—	(1,104)	—	(1,104)
Interest rate contracts	—	91	—	91
Commodity contracts	15	(13)	188	190
	15	(1,026)	188	(823)

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

September 30, 2026	Fair Value	Unobservable Input	Minimum Price/ Volatility	Maximum Price/ Volatility	Weighted Average Price/Volatility	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**8**	**Forward gas price**	**3.06**	**8.55**	**4.46**	**$/mmbtu[2]**
Crude	**35**	**Forward crude price**	**81.15**	**131.14**	**112.96**	**$/barrel**
Power	**(3)**	**Forward power price**	**31.51**	**202.39**	**86.66**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**5**	**Forward gas price**	**0.83**	**16.20**	**4.30**	**$/mmbtu[2]**
Crude	**40**	**Forward crude price**	**61.21**	**145.42**	**118.84**	**$/barrel**
Power	**(21)**	**Forward power price**	**45.73**	**184.88**	**97.42**	**$/MW/H**
Commodity options[3]						
Natural gas	**121**	**Forward gas price**	**1.37**	**16.31**	**4.32**	**$/mmbtu[2]**
		Price volatility	**38%**	**96%**	**75%**	
	185					

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

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. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives.

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

	Nine months ended September 30,	
	2026	2025
(millions of Canadian dollars)		
Level 3 net derivative asset/(liability) at beginning of period	**189**	(52)
Total gain/(loss), unrealized		
Included in earnings[1]	**94**	84
Included in OCI	**—**	(1)
Included in regulatory assets/liabilities	**(138)**	44
Settlements	**40**	115
Level 3 net derivative asset at end of period	**185**	190

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

There were no transfers into or out of Level 3 as at September 30, 2026 or December 31, 2025.

Net Investment Hedges
We currently have designated a portion of our US dollar-denominated debt as a hedge of our net investment in US dollar-denominated investments and subsidiaries.

During the nine months ended September 30, 2026 and 2025, we recognized unrealized foreign exchange losses of $525 million and gains of $297 million, respectively, on the translation of US dollar-denominated debt, in OCI. During the nine months ended September 30, 2026 and 2025, we recognized realized losses of nil and $81 million, respectively, associated with the settlement of US dollar-denominated debt that had matured during the period, in OCI.

Fair Value of Other Financial Instruments
Certain long-term investments in other entities with no actively quoted prices are classified as Fair Value Measurement Alternative (FVMA) investments and are recorded at cost less impairment. The carrying value of FVMA investments totaled $190 million and $185 million as at September 30, 2026 and December 31, 2025, respectively.

We have restricted long-term investments and cash held in trust for the purpose of funding pipeline abandonment in accordance with the CER's regulatory requirements under the LMCI, to cover future pipeline decommissioning costs in the state of Minnesota and to satisfy retirement obligations as Wexpro properties are abandoned. Information regarding these investments is as follows:

	September 30, 2026	December 31, 2025
(millions of Canadian dollars)		
Fair value		
Level 1	**1,085**	877
Level 2	**449**	416
Total fair value[1]	**1,534**	1,293
Cost		
Level 1	**861**	744
Level 2	**469**	426
Total cost	**1,330**	1,170

1 Investments are recognized at fair value and included in Restricted long-term investments and cash and Cash and cash equivalents in the Consolidated Statements of Financial Position.

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Unrealized holding gains/(losses)	**(4)**	50	**81**	96

During the nine months ended September 30, 2026, we purchased and sold investments totaling $402 million and $256 million, respectively (2025 - purchases of $1.1 billion and sales of $995 million). The resulting net cash flow impact is presented under Cash Flows from Investing Activities in the Consolidated Statements of Cash Flows.

We have a wholly-owned captive insurance subsidiary whose principal activity is providing insurance and reinsurance coverage for certain insurable property and casualty risk exposures of our operating subsidiaries and certain equity investments. As at September 30, 2026, our investments in debt securities held by our captive insurance subsidiary had a fair value and cost of $1.3 billion (December 31, 2025 - $1.2 billion). These investments in debt securities are recognized at fair value, classified as Level 2 in the fair value hierarchy, and are recorded in Long-term investments in the Consolidated Statements of Financial Position. There were unrealized holding losses of $30 million and $48 million for the three and nine months ended September 30, 2026, respectively (2025 - gains of nil and $1 million, respectively).

As at September 30, 2026, the maturities for our investments in debt securities were as follows:

	Total	Less than 1 year	5 years	10 years	Thereafter
(millions of Canadian dollars)					
Fair value of debt securities	1,291	73	895	248	75

As at September 30, 2026 and December 31, 2025, our long-term debt, including finance lease liabilities, had a carrying value before debt issuance costs of $113.2 billion and $104.4 billion, respectively, and a fair value of $109.2 billion and $102.7 billion, respectively.

The fair value of financial assets and liabilities other than derivative instruments, certain long-term investments in other entities, restricted long-term investments, investments held by our captive insurance subsidiary and long-term debt described above approximate their carrying value due to the short period to maturity.

12. INCOME TAXES

The effective income tax rates for the three months ended September 30, 2026 and 2025 were 23.3% and 27.2%, respectively, and for the nine months ended September 30, 2026 and 2025 were 23.4% and 22.9%, respectively.

The period-over-period changes in the effective income tax rates reflect changes in earnings between the comparative periods and the relative impacts of certain items recognized in each respective period, including higher US minimum tax, the absence of US investment tax credits in 2026, and the impact of rate-regulated accounting for income taxes largely attributable to the Reaccelerated Investment Incentive Property rules enacted in March 2026 as part of *Bill C-15 (45-1), Budget Implementation Act, No. 1*.

13. OTHER INCOME/(EXPENSE)

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Realized foreign currency loss	**(14)**	(80)	**(82)**	(366)
Unrealized foreign currency gain/(loss)	**24**	(425)	**(614)**	824
Net defined pension and OPEB credit	**75**	71	**213**	215
Other[1]	**188**	137	**542**	519
	273	(297)	**59**	1,192

1 Primarily consists of allowance for equity funds used during construction and third party interest income.

14. CONTINGENCIES

LITIGATION

We and our subsidiaries are subject to various 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.

INSURANCE

Not all risks are insurable or are insured by us. For those risks that we do insure, the majority are self-insured through our wholly-owned captive insurance subsidiary, which requires certain assumptions and management judgment regarding the frequency and severity of claims, claim development and settlement practices and the selection of estimated loss among estimates derived using different methods. Our self-insurance coverage is also subject to terms and conditions, exclusions and large deductibles which may reduce or eliminate coverage in certain circumstances. Our self-insurance coverage is generally renewed annually and premiums, terms, policy limits and/or deductibles can vary substantially based on factors like market conditions.

We can give no assurance that we will be able to maintain adequate self-insurance coverage in the future at rates or on other terms we consider commercially reasonable. In such a case, we may decide not to insure those risks.

In the unlikely event multiple insurable incidents occur which exceed coverage limits within the same insurance period, the total coverage will be allocated among entities on an equitable basis, based on an allocation agreement we have entered into with us and other subsidiaries.

ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

September 30, 2026

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 interim consolidated financial statements and the accompanying notes included in Part I. *Item 1. Financial Statements* of this quarterly report on Form 10-Q and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of our annual report on Form 10-K for the year ended December 31, 2025.

We continue to qualify as a foreign private issuer for purposes of the United States Securities Exchange Act of 1934, as amended (Exchange Act), as determined annually as of the end of our second fiscal quarter. We intend to continue to file annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K with the United States (US) Securities and Exchange Commission (SEC) instead of filing the reporting forms available to foreign private issuers. We also intend to maintain our Form S-3 registration statements.

RECENT DEVELOPMENTS

ACQUISITIONS

Tallgrass Energy Crude Acquisition

On September 9, 2026, Enbridge announced that, through a wholly-owned subsidiary, we entered into a definitive agreement with wholly-owned subsidiaries of Tallgrass Energy, LP (Tallgrass) to acquire its crude oil business for total cash consideration of approximately $3.62 billion (US$2.55 billion), subject to customary closing adjustments (the Tallgrass Crude Acquisition). The business comprises a 75% interest in Pony Express Pipeline (Pony Express), a 51% interest in the Powder River Gateway system, approximately 8.4 million barrels of crude oil storage capacity across nine terminals and 100% of Stanchion Energy, a crude marketing business. The transaction includes the PXP2 growth project, an approximately $0.4 billion (US$0.3 billion) expansion of Pony Express expected to increase the system's transportation capacity. The PXP2 project is expected to enter service in 2027. The Tallgrass Crude Acquisition will expand our presence in the Bakken, Powder River and Denver-Julesburg basins through Cushing, Oklahoma, complementing our Express-Platte and Seaway pipeline systems. The transaction is expected to close in the fourth quarter of 2026, subject to regulatory approvals and customary closing conditions.

Salt Creek Midstream Crude Acquisition

On October 9, 2026, through a wholly-owned subsidiary, we acquired from Salt Creek Midstream (Salt Creek) all of the membership interests of FS Crude Holdings, LLC (FS Crude) for total cash consideration of approximately $892 million (US$625 million) (the Salt Creek Crude Acquisition). FS Crude owns 100% of the Orla and Wink North systems and 50% of the Delaware Crossing system, which combined include approximately 500 miles of crude oil gathering infrastructure located in the Delaware Basin. The Salt Creek Crude Acquisition is expected to strengthen our crude oil value chain in the Permian Basin by providing a strategic connection between crude oil production and our Gray Oak and Cactus II Pipeline systems, as well as our Enbridge Ingleside Energy Center.

Wexpro Gas Supply Acquisition

On August 25, 2026, we entered into a definitive agreement to acquire substantially all of the assets of Laramie Energy, LLC (Laramie) for cash consideration of approximately $689 million (US$485 million) plus up to approximately $92 million (US$65 million) in contingent payments. The acquisition will expand Wexpro's natural gas production platform and provide stable, cost-of-service natural gas supply for Enbridge Gas Utah. Upon closing, the transaction is expected to increase Wexpro's contribution to Enbridge Gas Utah's supply portfolio and support long-term customer affordability and reliability. The transaction is expected to close in the fourth quarter of 2026, subject to regulatory approvals and customary closing conditions.

NONCONTROLLING INTEREST INVESTMENT

BC Pipeline System

On September 3, 2026, KKR & Co. Inc. (KKR), in collaboration with funds and affiliates managed by Apollo, invested $729 million in Westcoast Expansion Financing Limited Partnership (Westcoast Expansion) in respect of expenditures previously funded by Westcoast Energy LP Inc. Westcoast Expansion holds an ownership interest in Westcoast Energy Limited Partnership, which owns and operates our Westcoast Energy Inc. British Columbia (BC) Pipeline system. In addition to the initial cash consideration, KKR has committed to contribute approximately $2.0 billion to fund the Aspen Point and Sunrise Expansion Programs.

Subsequent to this investment, we hold a controlling interest in these assets, which are included in our Gas Transmission segment, and continue to manage and operate the pipeline system. Upon the Sunrise Expansion Program entering service, KKR and Apollo are expected to hold a 29% indirect, cumulative interest in the BC Pipeline system.

GAS TRANSMISSION RATE PROCEEDINGS

East Tennessee

East Tennessee Natural Gas, LLC (East Tennessee) filed a rate case on April 29, 2025 and a settlement in principle was reached with all active participants in April 2026. The settlement agreement was filed in May 2026 and approved by the Federal Energy Regulatory Commission on August 3, 2026 with rates effective retroactively to November 1, 2025.

BC Pipeline System

The 2022-2026 toll settlement agreement for our BC Pipeline system is expiring in December 2026. We anticipate a settlement will be finalized early in 2027. We expect to file interim tolls for our BC Pipeline system with the Canada Energy Regulator (CER) in the fourth quarter of 2026, with interim tolls effective January 1, 2027, pending regulatory approval.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

Enbridge Gas Ontario

In relation to Enbridge Gas Inc. (Enbridge Gas Ontario)'s application with the Ontario Energy Board (OEB) to establish a 2024-2028 Incentive Regulation rate setting framework, undertaken in three phases, Enbridge Gas Ontario continues to appeal the OEB's Phase 1 findings on depreciation, equity thickness, and undepreciated capital through the Ontario courts. The Phase 1 judicial review and appeal hearing took place in the second quarter of 2026.

In March 2026, the OEB issued a decision approving the settlement proposal for Phase 3 of Enbridge Gas Ontario's application, which addressed cost allocation and the harmonization of rates, rate classes, and services. The remaining non-ratemaking Phase 3 matters were addressed through a written hearing process, with a decision expected in the fourth quarter of 2026.

Enbridge Gas Ohio

In September 2026, Enbridge Gas Ohio filed a stipulation addressing the issues raised in its December 2025 rate case, which proposed a rate increase to recover Enbridge Gas Ohio's investment in distribution infrastructure and other costs to serve. The stipulation provides for a revised annual revenue increase of US$145 million, with a return on equity of 9.59% and equity thickness of 52.87%. The stipulation supports continued investment in the safety, reliability and modernization of our system. It also provides an increased contribution to the low-income energy assistance fund and contains multiple commitments to expand Enbridge Gas Ohio’s customer outreach and affordability support initiatives.

A decision on the filing is expected in or before the first quarter of 2027, with new rates expected to be effective on March 1, 2027.

FINANCING UPDATE

We completed long-term debt issuances totaling $3.0 billion and US$2.0 billion during the nine months ended September 30, 2026. Refer to *Liquidity and Capital Resources*.

During our annual renewal process, we renewed and extended approximately $22.3 billion of our credit facilities with maturities ranging from 2027-2031.

On May 11, 2026, Enbridge Pipelines Inc. (EPI) redeemed, at par, all of the outstanding $400 million 3.00% medium-term notes that carried an original maturity date in August 2026.

On June 16, 2026, we completed an exchange of all outstanding series of EPI medium term notes (EPI Notes) for an equal principal amount of newly issued medium term notes of Enbridge Inc. (Enbridge Notes), with financial terms identical to those of the EPI Notes (the Note Exchange Transaction) and which are unconditionally guaranteed by Spectra Energy Partners, LP (SEP) and Enbridge Energy Partners, L.P (EEP).

On September 14, 2026, we closed a public offering of 44,735,000 common shares of Enbridge at a price of $66.85 per share for gross proceeds of $3.0 billion. Net proceeds from the sale of common shares will be used to partially fund the Tallgrass Crude and Salt Creek Crude Acquisitions, with the remaining proceeds available to fund future growth opportunities. Refer to Part I. *Item 1. Financial Statements - Note 6 - Acquisitions and Dispositions*.

In October 2026, Public Service Company of North Carolina, Incorporated (Enbridge Gas North Carolina) closed a two-tranche offering consisting of ten-year and thirty-year senior notes for an aggregate principal amount of US$500 million which mature in October 2036 and October 2056, respectively.

These financing activities, in combination with the financing activities executed in 2025, are expected to provide sufficient liquidity to enable us to fund our current portfolio of capital projects and other operating working capital requirements through potential periods of extended market disruption without requiring access to the capital markets, should market access be restricted or pricing be unattractive. Refer to *Liquidity and Capital Resources*.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this management's discussion and analysis (MD&A) 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: our corporate vision and strategy, including strategic priorities and enablers; expected supply of, demand for, exports of and prices of crude oil, natural gas, natural gas liquids (NGL), liquefied natural gas (LNG), renewable natural gas (RNG) and renewable energy; energy evolution and lower-carbon energy, and our approach thereto; our sustainability goals, practices and performance; industry and market conditions; anticipated utilization of our assets; dividend growth and payout policy; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission, Gas Distribution and Storage, and Renewable Power Generation businesses; the characteristics, anticipated benefits, financing and timing of our acquisitions, dispositions and other transactions; expected future actions of regulators and courts; government trade policies and potential impacts of potential and announced tariffs, duties, fees, economic sanctions, or other trade measures and the timing thereof; expected costs, benefits and in-service dates related to announced projects and projects under construction; expected capital expenditures; investable capacity and capital allocation priorities; expected equity funding requirements for our commercially secured growth program; expected future growth, development and expansion opportunities; expected optimization and efficiency opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; toll and rate case discussions and proceedings and anticipated timeline and impact therefrom, including those relating to the Gas Distribution and Storage and Gas Transmission businesses; operational, industry, regulatory, climate change and other risks associated with our businesses; and our assessment of the potential impact of the various risk factors identified herein.

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 the following: the expected supply of, demand for, export of and prices of crude oil, natural gas, NGL, LNG, RNG and renewable energy; anticipated utilization of our assets; exchange rates; inflation; interest rates; tariffs and trade policies; availability and price of labor and construction materials; the stability of our supply chain; operational reliability; maintenance of support and regulatory approvals for our projects and transactions; anticipated in-service dates; weather; the timing, terms and closing of acquisitions, dispositions and other transactions; the realization of anticipated benefits of transactions; governmental legislation; litigation; estimated future dividends and impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; hedging program; expected earnings before interest, income taxes, and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows; and expected distributable cash flow. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL, LNG, RNG 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, interest rates and tariffs 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. 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 stability of our supply chain; 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, court 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 successful execution of our strategic priorities; operating performance; legislative and regulatory parameters; litigation; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; evolving government trade policies, including potential and announced tariffs, duties, fees, economic sanctions or other trade measures; operational dependence on third parties; 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; exchange rates; inflation; interest rates; commodity prices; access to and cost of capital; our ability to maintain adequate self-insurance in the future at commercially reasonable rates and terms; political decisions; global geopolitical conflicts and conditions; and the supply of, demand for and prices of commodities and other alternative energy, including but not limited to, those risks and uncertainties discussed in this MD&A and in our other filings with Canadian and US securities regulators. The impact of any one assumption, 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, we assume no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All 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.

NON-GAAP AND OTHER FINANCIAL MEASURES

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) makes reference to non-GAAP and other financial measures, including EBITDA. EBITDA is defined as earnings before interest, income taxes and depreciation and amortization. Management uses EBITDA to assess performance of Enbridge Inc. (Enbridge) and to set targets. Management believes the presentation of EBITDA gives useful information to investors as it provides increased transparency and insight into the performance of Enbridge.

The non-GAAP and other financial measures are not measures that have a standardized meaning prescribed by the accounting principles generally accepted in the US (US GAAP) and are not US GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is set out in this MD&A and is available on our website. Additional information on non-GAAP and other financial measures may be found on our website, www.sedarplus.ca or www.sec.gov.

RESULTS OF OPERATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars, except per share amounts)				
Segment earnings/(loss) before interest, income taxes and depreciation and amortization[1]				
Liquids Pipelines	**2,133**	2,283	**6,713**	7,207
Gas Transmission	**1,458**	1,270	**4,461**	4,185
Gas Distribution and Storage	**665**	560	**3,252**	2,670
Renewable Power Generation	**113**	89	**419**	421
Eliminations and Other	**49**	(379)	**(571)**	828
Earnings before interest, income taxes and depreciation and amortization[1]	**4,418**	3,823	**14,274**	15,311
Depreciation and amortization	**(1,490)**	(1,398)	**(4,352)**	(4,197)
Interest expense	**(1,049)**	(1,262)	**(3,666)**	(3,777)
Income tax expense	**(438)**	(316)	**(1,467)**	(1,679)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	**(46)**	(59)	**(115)**	(227)
Preference share dividends	**(107)**	(106)	**(319)**	(311)
Earnings attributable to common shareholders	**1,288**	682	**4,355**	5,120
Earnings per common share attributable to common shareholders	**0.59**	0.30	**2.00**	2.34
Diluted earnings per common share attributable to common shareholders	**0.59**	0.30	**1.99**	2.33

1 Non-GAAP financial measure. Refer to Non-GAAP and Other Financial Measures.

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Three months ended September 30, 2026, compared with the three months ended September 30, 2025

Earnings attributable to common shareholders were positively impacted by $529 million due to certain infrequent or other non-operating factors, primarily explained by:

- a non-cash, net unrealized derivative fair value gain of $245 million ($193 million after-tax) in 2026, compared with a net unrealized loss of $394 million ($299 million after-tax) in 2025, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange, interest rate and commodity price risks; and
- a net positive adjustment to crude oil inventory of $66 million ($51 million after-tax) in 2026, compared with a net negative adjustment of $7 million ($5 million after-tax) in 2025.

The non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of our comprehensive economic hedging program to mitigate foreign exchange, interest rate and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on 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 non-operating factors above, the remaining $77 million increase in earnings attributable to common shareholders is primarily explained by:

- higher contribution from our Gas Transmission segment primarily due to the East Tennessee rate case settlement and the Texas Eastern Transmission, LP (Texas Eastern) previously approved rate increase; and
- higher contribution from our Gas Distribution and Storage segment primarily due to higher base rates for Enbridge Gas Utah and Enbridge Gas North Carolina; partially offset by
- lower contribution from our Liquids Pipelines segment primarily due to lower Mainline tolls on Line 9 deliveries and lower contributions from Market Access volumes to the US Gulf Coast; and
- higher depreciation and amortization expense due to projects and capital placed into service since the third quarter of 2025.

Nine months ended September 30, 2026, compared with the nine months ended September 30, 2025

Earnings attributable to common shareholders were negatively impacted by $694 million due to certain infrequent or other non-operating factors, primarily explained by:

- a non-cash, net unrealized derivative fair value loss of $189 million ($146 million after-tax) in 2026, compared with a net unrealized gain of $944 million ($742 million after-tax) in 2025, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange, interest rate and commodity price risks; partially offset by
- the absence in 2026 of an impairment of $330 million ($261 million after-tax) of certain rate-regulated assets related to pension and other disallowances as a result of the Public Utilities Commission of Ohio's June 2025 order related to Enbridge Gas Ohio's rate case.

After taking into consideration the non-operating factors above, the remaining $71 million decrease in earnings attributable to common shareholders is primarily explained by:

- lower contribution from our Liquids Pipelines segment as a result of lower Mainline volumes, net of earnings sharing, lower Mainline tolls on Line 9 deliveries, and the absence in 2026 of equity earnings attributable to a litigation settlement;
- higher depreciation and amortization expense due to projects and capital placed into service since the third quarter of 2025;
- higher interest expense mainly due to incremental long-term debt issuances (net of lower interest on short-term borrowings); partially offset by
- higher contribution from our Gas Distribution and Storage segment due to higher rates, customer growth and higher storage and transportation pricing and sales at Enbridge Gas Ontario, as well as higher base rates for Enbridge Gas Utah and Enbridge Gas North Carolina; and
- higher contributions from our Gas Transmission segment primarily due to the East Tennessee rate case settlement and the Texas Eastern previously approved rate increase.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**2,133**	2,283	**6,713**	7,207

Three months ended September 30, 2026, compared with the three months ended September 30, 2025

EBITDA was negatively impacted by $49 million due to certain infrequent or other non-operating factors, primarily explained by:

- a non-cash, net unrealized loss of $109 million in 2026, compared with a net unrealized gain of $16 million in 2025, reflecting changes in the mark-to-market value of derivative financial instruments used to manage commodity price risks; partially offset by
- a net positive adjustment to crude oil inventory of $66 million in 2026, compared with a net negative adjustment of $7 million in 2025.

After taking into consideration the non-operating factors above, the remaining $101 million decrease is primarily explained by the following significant business factors:

- lower Mainline volumes, net of earnings sharing and lower Mainline tolls on Line 9 deliveries; and
- lower contributions from Market Access due to underutilized contracts to the US Gulf Coast; partially offset by
- the favorable effect of translating US dollar earnings at a higher average exchange rate in 2026, compared to the same period in 2025.

Nine months ended September 30, 2026, compared with the nine months ended September 30, 2025

EBITDA was negatively impacted by $80 million due to certain infrequent or other non-operating factors, primarily explained by a non-cash, net unrealized loss of $29 million in 2026, compared with a net unrealized gain of $54 million in 2025, reflecting changes in the mark-to-market value of derivative financial instruments used to manage commodity price risks.

After taking into consideration the non-operating factor above, the remaining $414 million decrease is primarily explained by the following significant business factors:

- lower Mainline volumes, net of earnings sharing and lower Mainline tolls on Line 9 deliveries;
- lower contributions from Market Access volumes to the US Gulf Coast;
- the absence in 2026 of equity earnings attributable to a litigation settlement; and
- the unfavorable effect of translating US dollar earnings at a lower average exchange rate in 2026, compared to the same period in 2025.

GAS TRANSMISSION

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**1,458**	1,270	**4,461**	4,185

Three months ended September 30, 2026, compared with the three months ended September 30, 2025

EBITDA was positively impacted by $188 million, primarily explained by the following significant business factors:

- increased revenues attributable to the East Tennessee rate case settlement, the Texas Eastern previously approved rate increase and favorable Texas Eastern contracting;
- higher allowance for equity funds used during construction from increased spend on growth projects; and
- the favorable effect of translating US dollar earnings at a higher average exchange rate in 2026, compared to the same period in 2025.

Nine months ended September 30, 2026 compared with the nine months ended September 30, 2025

EBITDA was positively impacted by $276 million, primarily explained by the following significant business factors:

- increased revenues attributable to the East Tennessee rate case settlement, the Texas Eastern previously approved rate increase and favorable Texas Eastern contracting; and
- higher allowance for equity funds used during construction from increased spend on growth projects; partially offset by
- the unfavorable effect of translating US dollar earnings at a lower average exchange rate in 2026, compared to the same period in 2025.

GAS DISTRIBUTION AND STORAGE

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**665**	560	**3,252**	2,670

Three months ended September 30, 2026, compared with the three months ended September 30, 2025

EBITDA was positively impacted by $105 million, primarily explained by the following significant business factors:

- higher base rates for Enbridge Gas Utah and Enbridge Gas North Carolina due to recent rate cases; and
- higher distribution margin from higher rates and customer growth, net of earnings sharing, at Enbridge Gas Ontario.

Nine months ended September 30, 2026, compared with the nine months ended September 30, 2025

EBITDA was positively impacted by $330 million due to the absence in 2026 of an impairment of certain rate-regulated assets in 2025 related to Enbridge Gas Ohio's rate case.

After taking into consideration the non-operating factor above, the remaining $252 million increase is primarily explained by the following significant business factors:

- higher distribution margin from higher rates and customer growth, net of earnings sharing, and higher storage pricing and short-term sales at Enbridge Gas Ontario; and
- higher base rates for Enbridge Gas Utah and Enbridge Gas North Carolina due to recent rate cases.

RENEWABLE POWER GENERATION

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**113**	89	**419**	421

Three months ended September 30, 2026, compared with the three months ended September 30, 2025

EBITDA was positively impacted by $24 million, largely driven by contributions from Sequoia Solar Phase 1, which was placed in service in December 2025.

Nine months ended September 30, 2026, compared with the nine months ended September 30, 2025

EBITDA was comparable period-over-period, primarily explained by:

- higher European wind resources; and
- contributions from Sequoia Solar Phase 1 in 2026; offset by
- the absence in 2026 of equity earnings related to investment tax credits from Fox Squirrel Solar, which came into service in 2025.

ELIMINATIONS AND OTHER

	Three months ended September 30,		Nine months ended September 30,	
	2026	2025	**2026**	2025
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**49**	(379)	**(571)**	828

Eliminations and Other includes operating and administrative costs that are not allocated to business segments, and the impact of foreign exchange hedge settlements and the activities of our wholly-owned captive insurance subsidiary. Eliminations and Other also includes our natural gas and power marketing businesses and the impact of new business development activities and corporate investments.

Three months ended September 30, 2026, compared with the three months ended September 30, 2025

EBITDA was positively impacted by $457 million due to certain infrequent or non-operating factors, primarily explained by a non-cash, net unrealized gain of $84 million in 2026, compared with a net unrealized loss of $397 million in 2025, reflecting 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 non-operating factor above, the remaining $29 million decrease in EBITDA is primarily explained by higher realized foreign exchange losses on hedge settlements in 2026.

Nine months ended September 30, 2026, compared with the nine months ended September 30, 2025

EBITDA was negatively impacted by $1.6 billion due to certain infrequent or non-operating factors, primarily explained by a non-cash, net unrealized loss of $528 million in 2026, compared with a net unrealized gain of $962 million in 2025, reflecting 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 non-operating factor above, the remaining $163 million increase in EBITDA is primarily explained by lower realized foreign exchange losses on hedge settlements in 2026.

GROWTH PROJECTS - COMMERCIALLY SECURED PROJECTS

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

		Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status[2]	Expected In-Service Date
(Canadian dollars, unless stated otherwise)						
LIQUIDS PIPELINES						
1.	Mainline Optimization Phase 1	100%	US$1.4 billion	US$0.2 billion	Pre-construction	2027
2.	Southern Illinois Connector	100%[3]	US$0.5 billion	No significant expenditures to date	Pre-construction	2028
3.	Pelican CO_2 Hub	50%	US$0.3 billion	No significant expenditures to date	Pre-construction	2029
GAS TRANSMISSION						
4.	Texas Eastern Modernization	100%	US$0.4 billion	US$0.4 billion	Various stages	2026
5.	T-North Expansion (Aspen Point)	100%[4,5]	$1.2 billion	$1.1 billion	In service	2026
6.	Tennessee Ridgeline Expansion	100%	US$1.5 billion	US$1.4 billion	In service[6]	2026
7.	Woodfibre LNG[7]	30%	US$2.9 billion	US$2.1 billion	Under construction	2027
8.	T-South Expansion (Sunrise)	100%[4,5]	$4.0 billion	$1.1 billion	Under construction	2028
9.	T-North Expansion (Birch Grove)	100%[4]	$0.4 billion	No significant expenditures to date	Pre-construction	2028
10.	Canyon System Pipelines	100%	US$1.0 billion	US$0.3 billion	Pre-construction	2029
11.	Algonquin Gas Transmission Enhancement	100%	US$0.3 billion	No significant expenditures to date	Pre-construction	2029
12.	USGC Storage Growth Program	100%	US$0.8 billion	No significant expenditures to date	Pre-construction	2028 - 2033
GAS DISTRIBUTION AND STORAGE						
13.	Moriah Energy Center[8]	100%	US$0.6 billion	US$0.4 billion	Under construction	2027
14.	T-15 Reliability Project[8,9]	100%	US$0.7 billion	US$0.2 billion	Under construction	2027 - 2028

		Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status[2]	Expected In-Service Date
RENEWABLE POWER GENERATION						
15.	Sequoia Solar	100%	US$1.1 billion	US$1.1 billion	Various stages	2026
16.	Clear Fork Solar	100%	US$0.9 billion	US$0.5 billion	Under construction	2027
17.	Easter	100%	US$0.4 billion	US$0.3 billion	Under construction	2026 - 2027
18.	Cowboy Phase 1	100%	US$1.2 billion	US$0.4 billion	Under construction	2027
19.	Cone	100%	US$0.7 billion	US$0.2 billion	Pre-construction	2027
20.	Courseulles Offshore Wind[10]	21.7%	$1.0 billion (€0.6 billion)	$0.5 billion (€0.3 billion)	Under construction	2027

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 and status of the project are determined as at September 30, 2026.
3 Includes amounts for the construction of the Southern Illinois Connector Pipeline, which is expected to be 50% jointly-owned with Energy Transfer, costs to upgrade the Energy Transfer Crude Oil Pipeline, in which we have a 27.6% ownership interest, as well as amounts fully attributable to Enbridge.
4 Our redeemable noncontrolling interest holder, Stonlasec8 Indigenous Investments Limited Partnership, will have the opportunity to participate in designated capital programs once they have been completed or substantially completed. As a result, our ownership interest in the program(s) may change in future periods.
5 Our redeemable noncontrolling interest holder, KKR, will participate in designated capital programs once they have been completed or substantially completed. As a result, our ownership interest in the program(s) may change in future periods.
6 The project entered service in November 2026.
7 Our expected investment is approximately US$2.3 billion, with the remainder financed through non-recourse project level debt.
8 Previously approved projects that were acquired by Enbridge through the acquisition of Enbridge Gas North Carolina.
9 Includes approved capital costs for the second phase of the project which involves installation of additional compression to add capacity and is expected to go into service in 2028.
10 Our investment is approximately $0.3 billion, with the remainder financed through non-recourse project level debt.

A full description of each of our material projects is provided in our annual report on Form 10-K for the year ended December 31, 2025. Material updates that have occurred since the date of filing of our Form 10-K are discussed below.

GAS TRANSMISSION

- **T-South Expansion (Sunrise) -** In April 2026, the project received a positive decision from the Government of Canada's Governor in Council and the CER issued a certificate for the project. Facilities and pipeline construction activities commenced in the third quarter of 2026 and are ongoing.

- **USGC Storage Growth Program -** In addition to the expansions of our Egan Hub and Moss Bluff natural gas storage facilities in the US Gulf Coast, we sanctioned a 25 billion cubic foot expansion of our Tres Palacios Gas Storage facility. The development includes three new caverns and ancillary support infrastructure and is expected to enter service ratably from 2028 to 2030.

- **T-North Expansion (Birch Grove)** - The project received CER approval in September 2026. Construction is expected to begin in the first quarter of 2027 following the satisfaction of pre-construction conditions.

RENEWABLE POWER GENERATION

- **Cone -** A 300-megawatt (MW) onshore wind project in the Southwest Power Pool market near Lubbock, Texas fully contracted under a long-term offtake agreement. This project is anticipated to qualify for US tax credits and has an expected in-service date in 2027.

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 help 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 issuances and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures and acquisitions and fund debt retirements. We seek to maintain significant liquidity through access to committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements through periods of extended market disruptions without accessing the capital markets.

We have signed contracts committing to the purchase of services, pipe and other materials totaling approximately $5.7 billion, which are expected to be paid over the next five years.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives.

CAPITAL MARKET ACCESS

We enable access to capital markets, subject to market conditions, through maintenance of shelf prospectuses in the US and Canada that allow for issuances 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 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 September 30, 2026:

	Maturity[1]	Total Facility	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2028-2049	**8,046**	**6,883**	**1,163**
Enbridge (U.S.) Inc.	2027-2031	**10,675**	**5,895**	**4,780**
Enbridge Pipelines Inc.	2028	**2,000**	**1,996**	**4**
Enbridge Gas Inc.	2028	**2,500**	**1,535**	**965**
Total committed credit facilities		**23,221**	**16,309**	**6,912**

1 Maturity date is inclusive of the one-year term out option for certain credit facilities.
2 Includes facility draws and commercial paper issuances that are back-stopped by credit facilities.

In July 2026, we renewed our committed credit facilities. Refer to *Financing Update*.

In addition to the committed credit facilities noted above, we maintain $1.5 billion of uncommitted demand letter of credit facilities, of which $776 million was unutilized as at September 30, 2026. As at December 31, 2025, we had $1.6 billion of uncommitted demand letter of credit facilities, of which $932 million was unutilized.

As at September 30, 2026, our net available liquidity totaled $11.8 billion (December 31, 2025 - $10.8 billion), consisting of available credit facilities of $6.9 billion (December 31, 2025 - $9.7 billion) and unrestricted cash and cash equivalents of $4.9 billion (December 31, 2025 - $1.1 billion) 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 September 30, 2026, we were in compliance with all such debt covenant provisions.

LONG-TERM DEBT ISSUANCES

During the nine months ended September 30, 2026, we completed the following long-term debt issuances totaling $3.0 billion and US$2.0 billion:

Company	Issuance Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Inc.				
	February 2026	3.57%	medium term notes due February 2031	$850
	February 2026	4.35%	medium term notes due February 2036	$850
	February 2026	5.10%	medium term notes due February 2056	$300
	March 2026	4.85%	senior notes due March 2031	US$1,000
	March 2026	5.45%	senior notes due March 2036	US$1,000
Enbridge Gas Inc.				
	August 2026	4.65%	medium term notes due August 2036	$600
	August 2026	5.35%	medium term notes due August 2056	$400

In October 2026, Enbridge Gas North Carolina closed a two-tranche offering consisting of ten-year and thirty-year senior notes for an aggregate principal amount of US$500 million which mature in October 2036 and October 2056, respectively.

LONG-TERM DEBT REPAYMENTS

During the nine months ended September 30, 2026, we completed the following long-term debt repayments totaling $955 million, US$64 million and €22 million:

Company	Repayment Date			Principal Amount
(millions of Canadian dollars, unless otherwise stated)				
Enbridge Gas Inc.				
	June 2026	2.81%	medium term notes	$250
	August 2026	2.50%	medium term notes	$300
Enbridge Pipelines (Southern Lights) L.L.C.				
	June 2026	3.98%	senior notes	US$14
Enbridge Pipelines Inc.				
	May 2026	3.00%	medium term notes[1]	$400
Enbridge Southern Lights LP				
	June 2026	4.01%	senior notes	$5
Blauracke GmbH				
	April 2026	2.10%	senior notes	€22
Public Service Company of North Carolina, Incorporated				
	January 2026	6.99%	debentures	US$50

1 The notes carried an original maturity date of August 2026.

Cash flow growth, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and 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 EBITDA.

There are no material restrictions on our cash. Total Restricted cash of $98 million, as reported in the Consolidated Statements of Financial Position, primarily includes reinsurance security, cash collateral, future pipeline abandonment costs collected and held in trust, amounts received in respect of specific shipper commitments and capital projects. 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, as at September 30, 2026 and December 31, 2025, we had positive and negative working capital positions of $2.5 billion and $2.8 billion, respectively. The positive working capital position at September 30, 2026 was primarily driven by the increase in cash associated with the partial pre-funding of the Tallgrass Crude and Salt Creek Crude Acquisitions, while the negative working capital position at December 31, 2025 was driven by current liabilities associated with our growth capital program.

SOURCES AND USES OF CASH

	Nine months ended September 30,	
	2026	2025
(millions of Canadian dollars)		
Operating activities	**9,156**	9,159
Investing activities	**(9,585)**	(7,187)
Financing activities	**4,183**	(2,292)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**69**	(28)
Net change in cash and cash equivalents and restricted cash	**3,823**	(348)

Significant sources and uses of cash for the nine months ended September 30, 2026 and 2025 are summarized below:

Operating Activities
The primary factors impacting cash provided by operating activities period-over-period include changes in our operating assets and liabilities 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 and cash receipts and payments generally. Cash provided by operating activities is also impacted by changes in earnings and certain infrequent or other non-operating factors, as discussed in *Results of Operations*, as well as Distributions from equity investments.

Investing Activities
Cash used in investing activities includes capital expenditures to execute our 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. Cash used in investing activities is also impacted by acquisitions, dispositions and changes in contributions to, and distributions from, our equity investments. The increase in cash used in investing activities period-over-period was primarily due to higher capital expenditures, partially offset by a decrease in contributions to equity investments.

Financing Activities
Cash provided by financing activities primarily relates to issuances and repayments of external debt, as well as transactions with our common and preference shareholders relating to dividends, share issuances, and share redemptions. Cash provided by financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests and redeemable noncontrolling interests. The increase in cash provided by financing activities period-over-period was primarily due to:

- lower long-term debt repayments;
- issuance of common shares for net proceeds of $2.9 billion;
- higher net commercial paper and credit facility draws; partially offset by
- lower long-term debt issuances.

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, 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 fully and unconditionally guaranteed, on a senior unsecured basis, the outstanding series of senior notes of Enbridge. The Partnerships have also entered into supplemental indentures with Enbridge pursuant to which the Partnerships have issued full and unconditional guarantees, on a senior unsecured basis, of senior notes issued by Enbridge subsequent to January 22, 2019. On June 16, 2026, all outstanding series of EPI Notes were exchanged for an equal principal amount of newly issued Enbridge Notes, with financial terms identical to those of the EPI Notes and which are unconditionally guaranteed by the Partnerships. As a result of the guarantees, holders of any of the outstanding guaranteed notes of the Partnerships (the Guaranteed Partnership Notes) 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 (the Guaranteed Enbridge 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 notes.

Consenting SEP notes and EEP notes under Guarantees

SEP Notes[1]	EEP Notes[2]
3.38% Senior Notes due 2026	5.95% Notes due 2033
5.95% Senior Notes due 2043	6.30% Notes due 2034
4.50% Senior Notes due 2045	7.50% Notes due 2038
	5.50% Notes due 2040
	7.38% Notes due 2045

1 As at September 30, 2026, the aggregate outstanding principal amount of SEP notes was approximately US$1.7 billion.
2 As at September 30, 2026, the aggregate outstanding principal amount of EEP notes was approximately US$1.9 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
1.60% Senior Notes due 2026	3.20% Senior Notes due 2027
5.90% Senior Notes due 2026	5.70% Senior Notes due 2027
4.25% Senior Notes due 2026	6.55% Senior Notes due 2027
5.25% Senior Notes due 2027	3.55% Senior Notes due 2028
3.70% Senior Notes due 2027	4.90% Senior Notes due 2028
4.60% Senior Notes due 2028	6.10% Senior Notes due 2028
6.00% Senior Notes due 2028	Floating Rate Senior Notes due 2028
4.20% Senior Notes due 2028	6.05% Senior Notes due 2029
5.30% Senior Notes due 2029	3.52% Senior Notes due 2029
3.13% Senior Notes due 2029	6.50% Senior Notes due 2029
4.90% Senior Notes due 2030	2.99% Senior Notes due 2029
6.20% Senior Notes due 2030	4.21% Senior Notes due 2030
4.50% Senior Notes due 2031	3.90% Senior Notes due 2030
4.85% Senior Notes due 2031	7.22% Senior Notes due 2030
5.70% Sustainability-Linked Senior Notes due 2033	3.57% Senior Notes due 2031
2.50% Sustainability-Linked Senior Notes due 2033	2.82% Senior Notes due 2031
5.63% Senior Notes due 2034	7.20% Senior Notes due 2032
5.55% Senior Notes due 2035	6.10% Sustainability-Linked Senior Notes due 2032
5.20% Senior Notes due 2035	5.36% Sustainability-Linked Senior Notes due 2033
5.45% Senior Notes due 2036	3.10% Sustainability-Linked Senior Notes due 2033
4.50% Senior Notes due 2044	4.73% Senior Notes due 2034
5.50% Senior Notes due 2046	4.56% Senior Notes due 2035
4.00% Senior Notes due 2049	5.57% Senior Notes due 2035
3.40% Senior Notes due 2051	4.35% Senior Notes due 2036
6.70% Senior Notes due 2053	5.08% Senior Notes due 2036
5.95% Senior Notes due 2054	5.75% Senior Notes due 2039
	5.35% Senior Notes due 2039
	5.33% Senior Notes due 2040
	5.12% Senior Notes due 2040
	4.24% Senior Notes due 2042
	4.55% Senior Notes due 2043
	4.57% Senior Notes due 2044
	4.87% Senior Notes due 2044
	4.55% Senior Notes due 2045
	4.13% Senior Notes due 2046
	4.33% Senior Notes due 2049
	4.20% Senior Notes due 2051
	4.10% Senior Notes due 2051
	6.51% Senior Notes due 2052
	5.76% Senior Notes due 2053
	5.82% Senior Notes due 2053
	5.32% Senior Notes due 2054
	5.10% Senior Notes due 2056
	4.56% Senior Notes due 2064

1 As at September 30, 2026, the aggregate outstanding principal amount of the Enbridge US dollar-denominated notes was approximately US$21.8 billion.

2 As at September 30, 2026, the aggregate outstanding principal amount of the Enbridge Canadian dollar-denominated notes was approximately $20.9 billion.

Rules 3-10 and 13-01 of the US SEC Regulation S-X, together with Exchange Act Rule 12h-5, provide an exemption from the reporting requirements of the Exchange Act for fully consolidated subsidiary issuers of guaranteed securities and subsidiary guarantors and allow for summarized financial information in lieu of filing separate financial statements for each of the Partnerships.

The following Summarized Combined Statement of Earnings and Summarized Combined Statements of Financial Position combine the balances of SEP, EEP and Enbridge.

Summarized Combined Statement of Earnings

Nine months ended September 30,	**2026**
(millions of Canadian dollars)	
Operating income	**76**
Earnings	**1,440**
Earnings attributable to common shareholders	**1,121**

Summarized Combined Statements of Financial Position

	September 30, 2026	December 31, 2025
(millions of Canadian dollars)		
Cash and cash equivalents	**2,884**	391
Accounts receivable from affiliates	**5,142**	3,873
Short-term loans receivable from affiliates	**3,635**	6,239
Other current assets	**594**	467
Long-term loans receivable from affiliates	**55,492**	46,858
Other long-term assets	**2,741**	1,994
Accounts payable to affiliates	**1,978**	2,079
Short-term loans payable to affiliates	**3,278**	2,082
Trade payables and accrued liabilities	**439**	537
Other current liabilities	**8,618**	6,990
Long-term loans payable to affiliates	**35,658**	34,488
Other long-term liabilities	**75,114**	67,004

The Guaranteed Enbridge Notes and the Guaranteed Partnership Notes are structurally subordinated to the indebtedness of the Subsidiary Non-Guarantors in respect of the assets of those Subsidiary Non-Guarantors.

Under US bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time the indebtedness evidenced by its guarantee or, in some states, when payments become due under the guarantee:

- received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee and was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor's remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

The guarantees of the Guaranteed Enbridge Notes contain provisions to limit the maximum amount of liability that the Partnerships could incur without causing the incurrence of obligations under the guarantee to be a fraudulent conveyance or fraudulent transfer under US federal or state law.

Each of the Partnerships is entitled to a right of contribution from the other Partnership for 50% of all payments, damages and expenses incurred by that Partnership in discharging its obligations under the guarantees for the Guaranteed Enbridge Notes.

Under the terms of the guarantee agreement and applicable supplemental indentures, the guarantees of either of the Partnerships of any Guaranteed Enbridge Notes will be unconditionally released and discharged automatically upon the occurrence of any of the following events:

- any direct or indirect sale, exchange or transfer, whether by way of merger, sale or transfer of equity interests or otherwise, to any person that is not an affiliate of Enbridge, of any of Enbridge's direct or indirect limited partnership or other equity interests in that Partnership as a result of which the Partnership ceases to be a consolidated subsidiary of Enbridge;
- the merger of that Partnership into Enbridge or the other Partnership or the liquidation and dissolution of that Partnership;
- the repayment in full or discharge or defeasance of those Guaranteed Enbridge Notes, as contemplated by the applicable indenture or guarantee agreement;
- with respect to EEP, the repayment in full or discharge or defeasance of each of the consenting EEP notes listed above;
- with respect to SEP, the repayment in full or discharge or defeasance of each of the consenting SEP notes listed above; or
- with respect to any series of Guaranteed Enbridge Notes, with the consent of holders of at least a majority of the outstanding principal amount of that series of Guaranteed Enbridge Notes.

The guarantee obligations of Enbridge will terminate with respect to any series of Guaranteed Partnership Notes if that series is discharged or defeased.

The Partnerships also guarantee the obligations of Enbridge under its existing credit facilities.

LEGAL AND OTHER UPDATES

LINE 5 EASEMENT (BAD RIVER BAND)
This is a federal lawsuit in the US District Court for the Western District of Wisconsin (the Court) brought on July 23, 2019 by the Bad River Band of the Lake Superior Tribe of Chippewa Indians of the Bad River Reservation (the Band) against Enbridge and certain of its pipeline subsidiaries. The case concerns Enbridge's continued operation of Line 5 across the Bad River Reservation after certain easements expired in 2013.

The Band asserts claims in trespass and public nuisance and seeks ejectment (removal of the pipeline), along with monetary compensation for past and ongoing use of Reservation lands. Enbridge disputes the trespass finding, the availability of shutdown and removal remedies and asserts, among other things, that federal pipeline safety law preempts such relief, that continued operations do not present an imminent threat, and that treaty- and foreign-affairs considerations limit the remedies available.

In September 2022, the Court issued summary-judgment rulings that resolved several claims and determined that Enbridge was trespassing on certain Reservation parcels, while declining to order an immediate shutdown or removal of the pipeline. A bench trial was held in October 2022 on the remaining issues, including nuisance, injunctive relief, and the appropriate monetary remedy for trespass.

In June 2023, the Court issued a final order awarding US$5.1 million as compensation for past trespass, requiring ongoing quarterly payments while Line 5 operates without valid rights-of-way, imposing monitoring and shutdown requirements, and ordering Line 5 to cease operating on any parcel lacking a valid right-of-way by June 16, 2026.

Enbridge and the Band have filed a consolidated appeal and cross-appeal in the US Court of Appeals for the Seventh Circuit (Seventh Circuit) addressing liability and remedies. Upon request by the Seventh Circuit, the US Government filed a brief in the appeal as amicus curiae to address the effect of the 1977 Transit Pipelines Treaty. The Court stayed the shutdown order, which was to have taken effect in June 2026, pending the appellate decision.

On July 30, 2026, the Seventh Circuit issued its decision in this litigation. The Seventh Circuit confirmed that Enbridge is trespassing on the Bad River allotted parcels but rejected the Band's nuisance claim and an immediate shutdown of Line 5. The Seventh Circuit remanded the trespass damages and injunction issues back to the Court for further proceedings, directing it to recalculate any restitution and develop a remedy that provides Enbridge a reasonable opportunity to complete the Line 5 reroute around the Bad River Reservation. In overturning the Band's nuisance claim, the Seventh Circuit vacated the related monitoring and shutdown requirements, finding that pipeline safety matters fall within the jurisdiction of federal regulators under the *Pipeline Safety Act*.

On September 14, 2026, Enbridge filed a petition for rehearing to the Seventh Circuit, which was denied on September 30, 2026. The Court set a scheduling conference for December; we expect legal proceedings to continue through 2027.

DAKOTA ACCESS PIPELINE

We hold an effective 27.6% interest in the Bakken Pipeline System, which includes the Dakota Access Pipeline (DAPL). The Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed lawsuits in 2016 with the US Court for the District of Columbia (the District Court) challenging the US Army Corps of Engineers' (the Army Corps) easement for DAPL, citing concerns over the adequacy of the Army Corps' environmental review and tribal consultation process. The Oglala Sioux and Yankton Sioux Tribes also filed lawsuits alleging similar claims in 2018. In 2017 and again in 2020, the District Court found deficiencies in the Army Corps' environmental assessments and ordered the preparation of a full Environmental Impact Statement (EIS).

In July 2020, the District Court vacated the easement and ordered the pipeline shut down, but that order was stayed by the US Court of Appeals for the District of Columbia. In January 2021, the US Court of Appeals upheld the requirement for an EIS and confirmed the easement's vacatur, though it ruled that DAPL could continue operating absent an injunction. The US Supreme Court declined to review the case, and the Army Corps indicated it would not seek to halt operations during the review process.

On September 8, 2023, the Army Corps released a draft EIS evaluating five alternatives, including continued operation, shutdown, rerouting, and removal of the pipeline. No preferred alternative was identified. The public comment period closed in December 2023.

In December 2025, the Army Corps published the final EIS for DAPL. The final EIS includes an extensive analysis of spill risks from the pipeline, including the pipeline safety record of Energy Transfer Crude Oil Pipeline. The final EIS identified continued operation of the existing pipeline with additional conditions as the preferred alternative. On May 21, 2026, the Army Corps issued the final Record of Decision. The final decision included the additional conditions set out in the preferred alternative, including groundwater monitoring and leak detection.

Separately, on October 15, 2024, the Standing Rock Sioux Tribe filed a new complaint in the District Court seeking a permanent injunction against DAPL's operation, alleging that the Army Corps is unlawfully allowing continued operations without a valid easement or compliant Facility Response Plan. Dakota Access, LLC and 13 states intervened in support of continued operations. On March 28, 2025, the District Court dismissed the complaint. On May 27, 2025, the Tribe filed a notice of appeal, which was dismissed on the Tribe's own motion on June 23, 2026.

On October 8, 2026, the Standing Rock Sioux Tribe filed a new complaint in District Court against the Army Corps and the PHMSA, seeking vacatur of the Army Corps and PHMSA approvals, and requesting the shutdown of DAPL. Unless extended, the Army Corps and PHMSA have 60 days to respond to the complaint.

OTHER LITIGATION

We and our subsidiaries are subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits. 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.

CHANGES IN ACCOUNTING POLICIES

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