ENBRIDGE INC.

CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

June 30, 2021

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(unaudited; millions of Canadian dollars, except per share amounts)				
Operating revenues				
Commodity sales	**6,334**	2,936	**12,763**	10,325
Transportation and other services	**3,877**	4,326	**8,045**	7,534
Gas distribution sales	**737**	694	**2,277**	2,110
Total operating revenues *(Note 3)*	**10,948**	7,956	**23,085**	19,969
Operating expenses				
Commodity costs	**6,430**	2,858	**12,628**	10,021
Gas distribution costs	**289**	250	**1,239**	1,105
Operating and administrative	**1,484**	1,801	**3,043**	3,401
Depreciation and amortization	**929**	949	**1,861**	1,831
Total operating expenses	**9,132**	5,858	**18,771**	16,358
Operating income	**1,816**	2,098	**4,314**	3,611
Income from equity investments	**352**	327	**747**	490
Impairment of equity investments *(Note 8)*	**—**	—	**—**	(1,736)
Other income/(expense)				
Net foreign currency gain/(loss)	**159**	526	**311**	(430)
Other	**82**	98	**191**	(93)
Interest expense	**(618)**	(681)	**(1,275)**	(1,387)
Earnings before income taxes	**1,791**	2,368	**4,288**	455
Income tax expense *(Note 10)*	**(270)**	(591)	**(753)**	(42)
Earnings	**1,521**	1,777	**3,535**	413
Earnings attributable to noncontrolling interests	**(37)**	(36)	**(59)**	(5)
Earnings attributable to controlling interests	**1,484**	1,741	**3,476**	408
Preference share dividends	**(90)**	(94)	**(182)**	(190)
Earnings attributable to common shareholders	**1,394**	1,647	**3,294**	218
Earnings per common share attributable to common shareholders *(Note 5)*	**0.69**	0.82	**1.63**	0.11
Diluted earnings per common share attributable to common shareholders *(Note 5)*	**0.69**	0.82	**1.63**	0.11

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(unaudited; millions of Canadian dollars)				
Earnings	**1,521**	1,777	**3,535**	413
Other comprehensive income/(loss), net of tax				
Change in unrealized gain/(loss) on cash flow hedges	**(157)**	(48)	**213**	(561)
Change in unrealized gain/(loss) on net investment hedges	**129**	340	**222**	(375)
Other comprehensive income from equity investees	**24**	30	**2**	20
Excluded components of fair value hedges	**(1)**	5	**(2)**	8
Reclassification to earnings of loss on cash flow hedges	**61**	48	**113**	80
Reclassification to earnings of pension and other postretirement benefits (OPEB) amounts	**6**	4	**11**	7
Foreign currency translation adjustments	**(835)**	(2,701)	**(1,631)**	2,936
Other comprehensive income/(loss), net of tax	**(773)**	(2,322)	**(1,072)**	2,115
Comprehensive income/(loss)	**748**	(545)	**2,463**	2,528
Comprehensive (income)/loss attributable to noncontrolling interests	**(9)**	50	**(6)**	(95)
Comprehensive income/(loss) attributable to controlling interests	**739**	(495)	**2,457**	2,433
Preference share dividends	**(90)**	(94)	**(182)**	(190)
Comprehensive income/(loss) attributable to common shareholders	**649**	(589)	**2,275**	2,243

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(unaudited; millions of Canadian dollars, except per share amounts)				
Preference shares				
Balance at beginning and end of period	**7,747**	7,747	**7,747**	7,747
Common shares				
Balance at beginning of period	**64,772**	64,760	**64,768**	64,746
Shares issued on exercise of stock options	**8**	3	**12**	17
Balance at end of period	**64,780**	64,763	**64,780**	64,763
Additional paid-in capital				
Balance at beginning of period	**324**	202	**277**	187
Stock-based compensation	**5**	5	**16**	19
Options exercised	**(5)**	(2)	**(8)**	(18)
Change in reciprocal interest	**—**	—	**39**	12
Other	**—**	2	**—**	7
Balance at end of period	**324**	207	**324**	207
Deficit				
Balance at beginning of period	**(8,093)**	(7,808)	**(9,995)**	(6,314)
Earnings attributable to controlling interests	**1,484**	1,741	**3,476**	408
Preference share dividends	**(90)**	(94)	**(182)**	(190)
Dividends paid to reciprocal shareholder	**2**	5	**5**	10
Common share dividends declared	**(1,692)**	(1,641)	**(1,692)**	(1,641)
Modified retrospective adoption of *ASU 2016-13 Financial Instruments - Credit Losses*	**—**	—	**—**	(66)
Other	**1**	—	**—**	(4)
Balance at end of period	**(8,388)**	(7,797)	**(8,388)**	(7,797)
Accumulated other comprehensive income/(loss) *(Note 7)*				
Balance at beginning of period	**(1,675)**	3,989	**(1,401)**	(272)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	**(745)**	(2,236)	**(1,019)**	2,025
Balance at end of period	**(2,420)**	1,753	**(2,420)**	1,753
Reciprocal shareholding				
Balance at beginning of period	**(17)**	(47)	**(29)**	(51)
Change in reciprocal interest	**—**	—	**12**	4
Balance at end of period	**(17)**	(47)	**(17)**	(47)
Total Enbridge Inc. shareholders' equity	**62,026**	66,626	**62,026**	66,626
Noncontrolling interests				
Balance at beginning of period	**2,930**	3,448	**2,996**	3,364
Earnings attributable to noncontrolling interests	**37**	36	**59**	5
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax				
Change in unrealized loss on cash flow hedges	**(3)**	(1)	**(6)**	(3)
Foreign currency translation adjustments	**(25)**	(85)	**(47)**	93
Contributions	**6**	5	**9**	20
Distributions	**(77)**	(88)	**(143)**	(164)
Other	**2**	—	**2**	—
Balance at end of period	**2,870**	3,315	**2,870**	3,315
Total equity	**64,896**	69,941	**64,896**	69,941
Dividends paid per common share	**0.835**	0.810	**1.670**	1.620

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six months ended June 30,	
	2021	2020
(unaudited; millions of Canadian dollars)		
Operating activities		
Earnings	**3,535**	413
Adjustments to reconcile earnings to net cash provided by operating activities:		
Depreciation and amortization	**1,861**	1,831
Deferred income tax expense/(recovery)	**647**	(223)
Changes in unrealized (gain)/loss on derivative instruments, net *(Note 9)*	**(448)**	824
Income from equity investments	**(747)**	(490)
Distributions from equity investments	**737**	821
Impairment of equity investments *(Note 8)*	**—**	1,736
Gain on disposition	**(41)**	—
Other	**(128)**	210
Changes in operating assets and liabilities	**(625)**	103
Net cash provided by operating activities	**4,791**	5,225
Investing activities		
Capital expenditures	**(3,463)**	(2,352)
Long-term investments and restricted long-term investments	**(155)**	(335)
Distributions from equity investments in excess of cumulative earnings	**246**	253
Additions to intangible assets	**(118)**	(104)
Proceeds from disposition	**122**	245
Affiliate loans, net	**29**	27
Net cash used in investing activities	**(3,339)**	(2,266)
Financing activities		
Net change in short-term borrowings	**289**	(543)
Net change in commercial paper and credit facility draws	**739**	854
Debenture and term note issues, net of issue costs	**3,247**	3,479
Debenture and term note repayments	**(1,888)**	(3,268)
Contributions from noncontrolling interests	**9**	20
Distributions to noncontrolling interests	**(143)**	(164)
Common shares issued	**3**	3
Preference share dividends	**(182)**	(190)
Common share dividends	**(3,382)**	(3,280)
Redemption of preferred shares held by subsidiary	**(115)**	—
Other	**(40)**	(35)
Net cash used in financing activities	**(1,463)**	(3,124)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(20)**	(14)
Net decrease in cash and cash equivalents and restricted cash	**(31)**	(179)
Cash and cash equivalents and restricted cash at beginning of period	**490**	676
Cash and cash equivalents and restricted cash at end of period	**459**	497

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

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	June 30, 2021	December 31, 2020
(unaudited; millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents	**374**	452
Restricted cash	**85**	38
Accounts receivable and other	**6,108**	5,258
Accounts receivable from affiliates	**115**	66
Inventory	**1,480**	1,536
	8,162	7,350
Property, plant and equipment, net	**95,273**	94,571
Long-term investments	**13,358**	13,818
Restricted long-term investments	**573**	553
Deferred amounts and other assets	**8,576**	8,446
Intangible assets, net	**2,204**	2,080
Goodwill	**32,014**	32,688
Deferred income taxes	**567**	770
Total assets	**160,727**	160,276
Liabilities and equity		
Current liabilities		
Short-term borrowings	**1,410**	1,121
Accounts payable and other	**7,683**	9,228
Accounts payable to affiliates	**99**	22
Interest payable	**619**	651
Current portion of long-term debt	**3,739**	2,957
	13,550	13,979
Long-term debt	**63,090**	62,819
Other long-term liabilities	**8,238**	8,783
Deferred income taxes	**10,953**	10,332
	95,831	95,913
Contingencies *(Note 12)*		
Equity		
Share capital		
Preference shares	**7,747**	7,747
Common shares *(2,026 outstanding at June 30, 2021 and December 31, 2020)*	**64,780**	64,768
Additional paid-in capital	**324**	277
Deficit	**(8,388)**	(9,995)
Accumulated other comprehensive loss *(Note 7)*	**(2,420)**	(1,401)
Reciprocal shareholding	**(17)**	(29)
Total Enbridge Inc. shareholders' equity	**62,026**	61,367
Noncontrolling interests	**2,870**	2,996
	64,896	64,363
Total liabilities and equity	**160,727**	160,276

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, 2020. 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, 2020, except for the adoption of new standards *(Note 2)*. Amounts are stated in Canadian dollars unless otherwise noted.

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

2. CHANGES IN ACCOUNTING POLICIES

ADOPTION OF NEW ACCOUNTING STANDARDS
Reference Rate Reform
For eligible hedging relationships existing as at January 1, 2021 and prospectively, we have applied the optional expedient in Accounting Standards Update (ASU) 2020-04 whereby the modification of the hedging instrument does not result in an automatic hedging relationship de-designation. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Clarifying Interaction Between Equity Securities, Equity Method Investments and Derivatives
Effective January 1, 2021, we adopted ASU 2020-01 on a prospective basis. The new standard was issued in January 2020 and clarifies that observable transactions should be considered for the purpose of applying the measurement alternative in accordance with Accounting Standards Codification (ASC) 321 *Investments - Equity Securities* immediately before the application or upon discontinuance of the equity method of accounting. Furthermore, the ASU clarifies that forward contracts or purchased options on equity securities are not out of scope of ASC 815 *Derivatives and Hedging* guidance only because, upon the contracts' exercise, the equity securities could be accounted for under the equity method of accounting or fair value option. The adoption of this ASU did not have a material impact on our consolidated financial statements.

Accounting for Income Taxes
Effective January 1, 2021, we adopted ASU 2019-12 on a prospective basis. The new standard was issued in December 2019 with the intent of simplifying the accounting for income taxes. The accounting update removes certain exceptions to the general principles in ASC 740 *Income Taxes* as well as provides simplification by clarifying and amending existing guidance. The adoption of this ASU did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Accounting for Certain Lessor Leases with Variable Lease Payments

ASU 2021-05 was issued in July 2021 to amend lessor accounting for certain leases with variable lease payments that do not depend on a reference index or a rate and would have resulted in the recognition of a loss at lease commencement if classified as a sales-type or a direct financing lease. The ASU amends the classification requirements of such leases for lessors to result in an operating lease classification. ASU 2021-05 is effective January 1, 2022 and can be applied either retrospectively or prospectively with early adoption permitted. We are currently assessing the impact of the new standard on our consolidated financial statements.

Accounting for Modifications or Exchanges of Certain Equity-Classified Contracts

ASU 2021-04 was issued in May 2021 to clarify issuer accounting for modifications or exchanges of freestanding equity-classified written call options that remain equity classified after modification or exchange. The ASU requires an issuer to determine the accounting for the modification or exchange based on the economic substance of the modification or exchange. ASU 2021-04 is effective January 1, 2022 and should be applied prospectively. We are currently assessing the impact of the new standard on our consolidated financial statements.

Accounting for Convertible Instruments and Contracts in an Entity's Own Equity

ASU 2020-06 was issued in August 2020 to simplify accounting for certain financial instruments. The ASU eliminates the current models that require separation of beneficial conversion and cash conversion features from convertible instruments and simplifies the derivative scope exception guidance pertaining to equity classification of contracts in an entity's own equity. The ASU also introduces additional disclosures for convertible debt and freestanding instruments that are indexed to and settled in an entity's own equity. The ASU amends the diluted earnings per share guidance, including the requirement to use if-converted method for all convertible instruments and an update for instruments that can be settled in either cash or shares. ASU 2020-06 is effective January 1, 2022 and should be applied on a full or modified retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

3. REVENUES

REVENUE FROM CONTRACTS WITH CUSTOMERS

Major Products and Services

Three months ended June 30, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	**2,157**	**1,046**	**150**	**—**	**—**	**—**	**3,353**
Storage and other revenue	**37**	**63**	**51**	**—**	**—**	**—**	**151**
Gas gathering and processing revenue	**—**	**10**	**—**	**—**	**—**	**—**	**10**
Gas distribution revenue	**—**	**—**	**725**	**—**	**—**	**—**	**725**
Electricity and transmission revenue	**—**	**—**	**—**	**55**	**—**	**—**	**55**
Total revenue from contracts with customers	**2,194**	**1,119**	**926**	**55**	**—**	**—**	**4,294**
Commodity sales	**—**	**—**	**—**	**—**	**6,334**	**—**	**6,334**
Other revenue[1,2]	**215**	**9**	**12**	**77**	**1**	**6**	**320**
Intersegment revenue	**138**	**—**	**15**	**—**	**10**	**(163)**	**—**
Total revenue	**2,547**	**1,128**	**953**	**132**	**6,345**	**(157)**	**10,948**

Three months ended June 30, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	2,141	1,126	151	—	—	—	3,418
Storage and other revenue	24	66	56	—	—	—	146
Gas gathering and processing revenue	—	5	—	—	—	—	5
Gas distribution revenue	—	—	686	—	—	—	686
Electricity and transmission revenue	—	—	—	54	—	—	54
Total revenue from contracts with customers	2,165	1,197	893	54	—	—	4,309
Commodity sales	—	—	—	—	2,936	—	2,936
Other revenue[1,2]	598	5	8	96	11	(7)	711
Intersegment revenue	182	1	2	—	2	(187)	—
Total revenue	2,945	1,203	903	150	2,949	(194)	7,956

Six months ended June 30, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	**4,486**	**2,167**	**366**	**—**	**—**	**—**	**7,019**
Storage and other revenue	**63**	**137**	**109**	**—**	**—**	**—**	**309**
Gas gathering and processing revenue	**—**	**17**	**—**	**—**	**—**	**—**	**17**
Gas distribution revenue	**—**	**—**	**2,259**	**—**	**—**	**—**	**2,259**
Electricity and transmission revenue	**—**	**—**	**—**	**81**	**—**	**—**	**81**
Total revenue from contracts with customers	**4,549**	**2,321**	**2,734**	**81**	**—**	**—**	**9,685**
Commodity sales	**—**	**—**	**—**	**—**	**12,763**	**—**	**12,763**
Other revenue[1,2]	**427**	**21**	**18**	**168**	**1**	**2**	**637**
Intersegment revenue	**270**	**—**	**24**	**—**	**14**	**(308)**	**—**
Total revenue	**5,246**	**2,342**	**2,776**	**249**	**12,778**	**(306)**	**23,085**

Six months ended June 30, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Transportation revenue	4,581	2,381	366	—	—	—	7,328
Storage and other revenue	50	145	103	—	—	—	298
Gas gathering and processing revenue	—	12	—	—	—	—	12
Gas distribution revenue	—	—	2,103	—	—	—	2,103
Electricity and transmission revenue	—	—	—	104	—	—	104
Total revenue from contracts with customers	4,631	2,538	2,572	104	—	—	9,845
Commodity sales	—	—	—	—	10,325	—	10,325
Other revenue[1,2]	(419)	21	7	199	4	(13)	(201)
Intersegment revenue	267	1	6	—	18	(292)	—
Total revenue	4,479	2,560	2,585	303	10,347	(305)	19,969

1 *Includes mark-to-market gains from our hedging program for the three months ended June 30, 2021 and 2020 of $131 million and $531 million, respectively. For the six months ended June 30, 2021 and 2020, other revenue includes a $261 million mark-to-market gain and $575 million mark-to-market loss, respectively.*

2 *Includes revenues from lease contracts for the three months ended June 30, 2021 and 2020 of $143 million and $157 million, respectively and for the six months ended June 30, 2021 and 2020 of $302 million and $315 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 June 30, 2021	**1,755**	**213**	**1,708**
Balance as at December 31, 2020	2,042	226	1,815

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 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. Revenue recognized during the three and six months ended June 30, 2021 included in contract liabilities at the beginning of the period was $80 million and $225 million, respectively. Increases in contract liabilities from cash received, net of amounts recognized as revenues, during the three and six months ended June 30, 2021 were $76 million and $145 million, respectively.

Performance Obligations

There were no material revenues recognized in the three and six months ended June 30, 2021 from performance obligations satisfied in previous periods.

Revenues to be Recognized from Unfulfilled Performance Obligations
Total revenues from performance obligations expected to be fulfilled in future periods is $55.2 billion, of which $3.3 billion and $5.6 billion are expected to be recognized during the remaining six months ending December 31, 2021 and the year ending December 31, 2022, respectively.

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

Recognition and Measurement of Revenues

Three months ended June 30, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	**—**	**—**	**17**	**—**	**17**
Revenues from products and services transferred over time[1]	**2,194**	**1,119**	**909**	**55**	**4,277**
Total revenue from contracts with customers	**2,194**	**1,119**	**926**	**55**	**4,294**

Three months ended June 30, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	—	—	15	—	15
Revenues from products and services transferred over time[1]	2,165	1,197	878	54	4,294
Total revenue from contracts with customers	2,165	1,197	893	54	4,309

Six months ended June 30, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	**—**	**—**	**34**	**—**	**34**
Revenues from products and services transferred over time[1]	**4,549**	**2,321**	**2,700**	**81**	**9,651**
Total revenue from contracts with customers	**4,549**	**2,321**	**2,734**	**81**	**9,685**

Six months ended June 30, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Consolidated
(millions of Canadian dollars)					
Revenues from products transferred at a point in time	—	—	30	—	30
Revenues from products and services transferred over time[1]	4,631	2,538	2,542	104	9,815
Total revenue from contracts with customers	4,631	2,538	2,572	104	9,845

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

4. SEGMENTED INFORMATION

Three months ended June 30, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**2,547**	**1,128**	**953**	**132**	**6,345**	**(157)**	**10,948**
Commodity and gas distribution costs	**(7)**	**—**	**(299)**	**—**	**(6,567)**	**154**	**(6,719)**
Operating and administrative	**(673)**	**(424)**	**(242)**	**(37)**	**(9)**	**(99)**	**(1,484)**
Income from equity investments	**180**	**132**	**27**	**13**	**—**	**—**	**352**
Other income/(expense)	**(3)**	**32**	**19**	**7**	**(8)**	**194**	**241**
Earnings/(loss) before interest, income taxes, and depreciation and amortization	**2,044**	**868**	**458**	**115**	**(239)**	**92**	**3,338**
Depreciation and amortization							**(929)**
Interest expense							**(618)**
Income tax expense							**(270)**
Earnings							**1,521**
Capital expenditures[1]	**567**	**547**	**300**	**2**	**—**	**9**	**1,425**

Three months ended June 30, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	2,945	1,203	903	150	2,949	(194)	7,956
Commodity and gas distribution costs	(1)	—	(254)	—	(3,021)	168	(3,108)
Operating and administrative	(782)	(438)	(269)	(37)	(29)	(246)	(1,801)
Income/(loss) from equity investments	148	168	(8)	21	(2)	—	327
Other income	30	17	11	29	4	533	624
Earnings/(loss) before interest, income taxes, and depreciation and amortization	2,340	950	383	163	(99)	261	3,998
Depreciation and amortization							(949)
Interest expense							(681)
Income tax expense							(591)
Earnings							1,777
Capital expenditures[1]	561	429	204	7	1	19	1,221

Six months ended June 30, 2021	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	**5,246**	**2,342**	**2,776**	**249**	**12,778**	**(306)**	**23,085**
Commodity and gas distribution costs	**(10)**	**—**	**(1,257)**	**—**	**(12,920)**	**320**	**(13,867)**
Operating and administrative	**(1,492)**	**(858)**	**(514)**	**(80)**	**(23)**	**(76)**	**(3,043)**
Income from equity investments	**334**	**314**	**49**	**50**	**—**	**—**	**747**
Other income/(expense)	**5**	**43**	**38**	**52**	**(10)**	**374**	**502**
Earnings/(loss) before interest, income taxes, and depreciation and amortization	**4,083**	**1,841**	**1,092**	**271**	**(175)**	**312**	**7,424**
Depreciation and amortization							**(1,861)**
Interest expense							**(1,275)**
Income tax expense							**(753)**
Earnings							**3,535**
Capital expenditures[1]	**1,923**	**1,029**	**519**	**7**	**—**	**21**	**3,499**

Six months ended June 30, 2020	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution and Storage	Renewable Power Generation	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	4,479	2,560	2,585	303	10,347	(305)	19,969
Commodity and gas distribution costs	(8)	—	(1,126)	—	(10,264)	272	(11,126)
Operating and administrative	(1,647)	(945)	(518)	(87)	(57)	(147)	(3,401)
Income from equity investments	345	93	15	37	—	—	490
Impairment of equity investments	—	(1,736)	—	—	—	—	(1,736)
Other income/(expense)	21	(76)	31	30	(4)	(525)	(523)
Earnings/(loss) before interest, income taxes, and depreciation and amortization	3,190	(104)	987	283	22	(705)	3,673
Depreciation and amortization							(1,831)
Interest expense							(1,387)
Income tax expense							(42)
Earnings							413
Capital expenditures[1]	1,061	820	426	30	1	41	2,379

1 Includes allowance for equity funds used during construction.

5. EARNINGS PER COMMON SHARE AND DIVIDENDS PER SHARE

BASIC

Earnings per common share is calculated by dividing earnings attributable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of common shares outstanding has been reduced by our pro-rata weighted average interest in our own common shares of approximately 2 million and 3 million for the three and six months ended June 30, 2021, respectively, compared to 6 million for the three and six months ended June 30, 2020, resulting from our reciprocal investment in Noverco Inc. (Noverco).

DILUTED

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

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

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(number of shares in millions)				
Weighted average shares outstanding	**2,024**	2,019	**2,023**	2,019
Effect of dilutive options	**2**	1	**1**	2
Diluted weighted average shares outstanding	**2,026**	2,020	**2,024**	2,021

For the three months ended June 30, 2021 and 2020, 20.5 million and 34.6 million, respectively, of anti-dilutive stock options with a weighted average exercise price of \$50.66 and \$51.00, respectively, were excluded from the diluted earnings per common share calculation.

For the six months ended June 30, 2021 and 2020, 24.0 million and 25.7 million, respectively, of anti-dilutive stock options with a weighted average exercise price of \$51.10 and \$52.71, respectively, were excluded from the diluted earnings per common share calculation.

DIVIDENDS PER SHARE

On July 27, 2021, our Board of Directors declared the following quarterly dividends. All dividends are payable on September 1, 2021 to shareholders of record on August 13, 2021.

	Dividend per share
Common Shares[1]	$0.83500
Preference Shares, Series A	$0.34375
Preference Shares, Series B	$0.21340
Preference Shares, Series C[2]	$0.15753
Preference Shares, Series D	$0.27875
Preference Shares, Series F	$0.29306
Preference Shares, Series H	$0.27350
Preference Shares, Series J	US$0.30540
Preference Shares, Series L	US$0.30993
Preference Shares, Series N	$0.31788
Preference Shares, Series P	$0.27369
Preference Shares, Series R	$0.25456
Preference Shares, Series 1	US$0.37182
Preference Shares, Series 3	$0.23356
Preference Shares, Series 5	US$0.33596
Preference Shares, Series 7	$0.27806
Preference Shares, Series 9	$0.25606
Preference Shares, Series 11	$0.24613
Preference Shares, Series 13	$0.19019
Preference Shares, Series 15	$0.18644
Preference Shares, Series 17	$0.32188
Preference Shares, Series 19	$0.30625

1 The quarterly dividend per common share was increased 3% to $0.835 from $0.81, effective March 1, 2021.

2 The quarterly dividend per share paid on Series C was increased to $0.15501 from $0.15349 on March 1, 2021, and increased to $0.15753 from $0.15501 on June 1, 2021, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.

6. DEBT

CREDIT FACILITIES

The following table provides details of our committed credit facilities as at June 30, 2021:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2022-2024	**9,125**	**7,446**	**1,679**
Enbridge (U.S.) Inc.	2022-2024	**6,811**	**3,076**	**3,735**
Enbridge Pipelines Inc.	2022	**3,000**	**494**	**2,506**
Enbridge Gas Inc.	2022	**2,000**	**1,410**	**590**
Total committed credit facilities		**20,936**	**12,426**	**8,510**

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.

On February 10, 2021, Enbridge Inc. entered into a three year, revolving, extendible, sustainability-linked credit facility for $1.0 billion with a syndicate of lenders and concurrently terminated our one year, revolving, syndicated credit facility for $3.0 billion.

On February 25, 2021, two term loans with an aggregate total of US$500 million were repaid with proceeds from a floating rate notes issuance.

On July 22 and 23, 2021, we renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

In addition to the committed credit facilities noted above, we maintain $1.4 billion of uncommitted demand credit facilities, of which $978 million was unutilized as at June 30, 2021. As at December 31, 2020, we had $849 million of uncommitted demand credit facilities, of which $533 million was unutilized.

Our credit facilities carry a weighted average standby fee of 0.2% per annum on the unused portion and draws bear interest at market rates. Certain credit facilities serve as a back-stop to the commercial paper programs and we have the option to extend such facilities.

As at June 30, 2021 and December 31, 2020, commercial paper and credit facility draws, net of short-term borrowings and non-revolving credit facilities that mature within one year, of $9.0 billion and $9.9 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 six months ended June 30, 2021, we completed the following long-term debt issuances totaling US$2.0 billion and $800 million:

Company	Issue Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	Floating rate notes due February 2023[1]	US$500
	June 2021	2.50% Sustainability-Linked senior notes due August 2033	US$1,000
	June 2021	3.40% senior notes due August 2051	US$500
Enbridge Pipelines Inc.			
	May 2021	4.20% medium-term notes due May 2051	$400
	May 2021	2.82% medium-term notes due May 2031	$400

1 *Notes mature in two years and carry an interest rate set to equal Secured Overnight Financing Rate (SOFR) plus a margin of 40 basis points.*

LONG-TERM DEBT REPAYMENTS

During the six months ended June 30, 2021, we completed the following long-term debt repayments totaling $808 million and US$880 million:

Company	Repayment Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	4.26% medium-term notes	$200
	March 2021	3.16% medium-term notes	$400
Enbridge Energy Partners, L.P.			
	June 2021	4.20% senior notes	US$600
Enbridge Gas Inc.			
	May 2021	2.76% medium-term notes	$200
Enbridge Pipelines (Southern Lights) L.L.C.			
	June 2021	3.98% senior notes	US$30
Enbridge Southern Lights LP			
	June 2021	4.01% senior notes	$8
Spectra Energy Partners, LP			
	March 2021	4.60% senior notes	US$250

SUBORDINATED TERM NOTES

As at June 30, 2021 and December 31, 2020, our fixed-to-floating rate and fixed-to-fixed subordinated term notes had a principal value of $7.6 billion and $7.8 billion, respectively.

FAIR VALUE ADJUSTMENT

As at June 30, 2021 and December 31, 2020, the net fair value adjustments to total debt assumed in a historical acquisition were $703 million and $750 million, respectively. During the three months ended June 30, 2021 and 2020, amortization of the fair value adjustment recorded as a reduction to Interest expense in the Consolidated Statements of Earnings was $13 million and $14 million, respectively. During the six months ended June 30, 2021 and 2020, amortization of the fair value adjustment recorded as a reduction to Interest expense in the Consolidated Statements of Earnings was $25 million and $29 million, respectively.

DEBT COVENANTS

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at June 30, 2021, we were in compliance with all debt covenants.

7. COMPONENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

Changes in Accumulated Other Comprehensive Income (AOCI) attributable to our common shareholders for the six months ended June 30, 2021 and 2020 are as follows:

(millions of Canadian dollars)	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
Balance as at January 1, 2021	**(1,326)**	**5**	**(215)**	**568**	**66**	**(499)**	**(1,401)**
Other comprehensive income/(loss) retained in AOCI	**294**	**(2)**	**251**	**(1,584)**	**1**	**—**	**(1,040)**
Other comprehensive loss/(income) reclassified to earnings							
Interest rate contracts[1]	**142**	**—**	**—**	**—**	**—**	**—**	**142**
Foreign exchange contracts[2]	**3**	**—**	**—**	**—**	**—**	**—**	**3**
Other contracts[3]	**1**	**—**	**—**	**—**	**—**	**—**	**1**
Amortization of pension and OPEB actuarial loss and prior service costs[4]	**—**	**—**	**—**	**—**	**—**	**14**	**14**
Other	**17**	**—**	**—**	**(20)**	**3**	**—**	**—**
	457	**(2)**	**251**	**(1,604)**	**4**	**14**	**(880)**
Tax impact							
Income tax on amounts retained in AOCI	**(75)**	**—**	**(29)**	**—**	**1**	**—**	**(103)**
Income tax on amounts reclassified to earnings	**(33)**	**—**	**—**	**—**	**—**	**(3)**	**(36)**
	(108)	**—**	**(29)**	**—**	**1**	**(3)**	**(139)**
Balance as at June 30, 2021	**(977)**	**3**	**7**	**(1,036)**	**71**	**(488)**	**(2,420)**

	Cash Flow Hedges	Excluded Components of Fair Value Hedges	Net Investment Hedges	Cumulative Translation Adjustment	Equity Investees	Pension and OPEB Adjustment	Total
(millions of Canadian dollars)							
Balance as at January 1, 2020	(1,073)	—	(317)	1,396	67	(345)	(272)
Other comprehensive income/(loss) retained in AOCI	(738)	8	(375)	2,843	25	—	1,763
Other comprehensive loss reclassified to earnings							
Interest rate contracts[1]	103	—	—	—	—	—	103
Foreign exchange contracts[2]	2	—	—	—	—	—	2
Amortization of pension and OPEB actuarial loss and prior service costs[4]	—	—	—	—	—	9	9
	(633)	8	(375)	2,843	25	9	1,877
Tax impact							
Income tax on amounts retained in AOCI	180	—	—	—	(5)	—	175
Income tax on amounts reclassified to earnings	(25)	—	—	—	—	(2)	(27)
	155	—	—	—	(5)	(2)	148
Balance as at June 30, 2020	(1,551)	8	(692)	4,239	87	(338)	1,753

1 Reported within Interest expense in the Consolidated Statements of Earnings.
2 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.
3 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.
4 These components are included in the computation of net periodic benefit costs and are reported within Other income/(expense) in the Consolidated Statements of Earnings.

8. IMPAIRMENT OF EQUITY INVESTMENTS

DCP Midstream, LLC

DCP Midstream, LLC (DCP Midstream), a 50% owned equity method investment of Enbridge, holds an equity interest in DCP Midstream, LP. A decline in the market price of DCP Midstream, LP’s publicly traded units during the first quarter of 2020 resulted in an other than temporary impairment loss on our investment in DCP Midstream of $1.7 billion for the six months ended June 30, 2020. In addition, we incurred losses of $324 million through our equity earnings pick up in relation to asset and goodwill impairment losses recorded by DCP Midstream, LP during the six months ended June 30, 2020. The carrying value of our investment in DCP Midstream as at June 30, 2021 and December 31, 2020 was $286 million and $331 million, respectively.

Our investment in DCP Midstream forms part of our Gas Transmission and Midstream segment. The impairment losses were recorded within Impairment of equity investments in the Consolidated Statements of Earnings.

9. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET RISK

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

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

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

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying cash flow, fair value 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 foreign currency derivatives and 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 monitor our debt portfolio mix of fixed and variable rate debt instruments to manage a consolidated portfolio of floating rate debt within the Board of Directors approved policy limit of a maximum of 30% of floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk. Pay fixed-receive floating interest rate swaps may be used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 3.1%.

We are exposed to changes in the fair value of fixed rate debt that arise as a result of the changes in market interest rates. Pay floating-receive fixed interest rate swaps are used, when applicable, to hedge against future changes to the fair value of fixed rate debt which mitigates the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps. As at June 30, 2021, we do not have any pay floating-receive fixed interest rate swaps outstanding.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have established a program within some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 2.2%.

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

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

COVID-19 PANDEMIC RISK
The spread of the COVID-19 pandemic has caused significant volatility in Canada, the US and international markets. While we have taken proactive measures to deliver energy safely and reliably during this pandemic, given the ongoing dynamic nature of the circumstances surrounding COVID-19, including ongoing uncertainty as to the duration of the pandemic and corresponding public health measures, the impact of this pandemic and the ongoing recovery on our business remains uncertain.

TOTAL DERIVATIVE INSTRUMENTS
We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements, or other similar derivative agreements, with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events, and reduce our credit risk exposure on financial derivative asset positions outstanding with the counterparties in those circumstances.

The following table summarizes the maximum potential settlement amounts in the event of these specific circumstances. All amounts are presented gross in the Consolidated Statements of Financial Position.

June 30, 2021	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)						
Accounts receivable and other						
Foreign exchange contracts	—	—	312	312	(29)	283
Commodity contracts	—	—	219	219	(174)	45
Other contracts	1	—	5	6	—	6
	1	—	536	537	(203)	334
Deferred amounts and other assets						
Foreign exchange contracts	—	—	493	493	(207)	286
Interest rate contracts	157	—	—	157	(23)	134
Commodity contracts	—	—	64	64	(40)	24
Other contracts	2	—	2	4	—	4
	159	—	559	718	(270)	448
Accounts payable and other						
Foreign exchange contracts	(14)	(153)	(110)	(277)	29	(248)
Interest rate contracts	(156)	—	—	(156)	—	(156)
Commodity contracts	(9)	—	(356)	(365)	174	(191)
	(179)	(153)	(466)	(798)	203	(595)
Other long-term liabilities						
Foreign exchange contracts	—	—	(435)	(435)	207	(228)
Interest rate contracts	(123)	—	(23)	(146)	23	(123)
Commodity contracts	(5)	—	(93)	(98)	40	(58)
	(128)	—	(551)	(679)	270	(409)
Total net derivative assets/(liabilities)						
Foreign exchange contracts	(14)	(153)	260	93	—	93
Interest rate contracts	(122)	—	(23)	(145)	—	(145)
Commodity contracts	(14)	—	(166)	(180)	—	(180)
Other contracts	3	—	7	10	—	10
	(147)	(153)	78	(222)	—	(222)

December 31, 2020	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)						
Accounts receivable and other						
Foreign exchange contracts	—	—	180	180	(28)	152
Interest rate contracts	—	—	—	—	—	—
Commodity contracts	—	—	143	143	(81)	62
	—	—	323	323	(109)	214
Deferred amounts and other assets						
Foreign exchange contracts	14	—	452	466	(218)	248
Interest rate contracts	56	—	—	56	(25)	31
Commodity contracts	—	—	39	39	(9)	30
	70	—	491	561	(252)	309
Accounts payable and other						
Foreign exchange contracts	(5)	(29)	(151)	(185)	28	(157)
Interest rate contracts	(423)	—	(2)	(425)	—	(425)
Commodity contracts	(2)	—	(278)	(280)	81	(199)
Other contracts	(1)	—	(3)	(4)	—	(4)
	(431)	(29)	(434)	(894)	109	(785)
Other long-term liabilities						
Foreign exchange contracts	—	(87)	(673)	(760)	218	(542)
Interest rate contracts	(218)	—	(23)	(241)	25	(216)
Commodity contracts	(1)	—	(57)	(58)	9	(49)
	(219)	(87)	(753)	(1,059)	252	(807)
Total net derivative assets/(liabilities)						
Foreign exchange contracts	9	(116)	(192)	(299)	—	(299)
Interest rate contracts	(585)	—	(25)	(610)	—	(610)
Commodity contracts	(3)	—	(153)	(156)	—	(156)
Other contracts	(1)	—	(3)	(4)	—	(4)
	(580)	(116)	(373)	(1,069)	—	(1,069)

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

June 30, 2021	2021	2022	2023	2024	2025	Thereafter	Total
Foreign exchange contracts - US dollar forwards - purchase *(millions of US dollars)*	**1,364**	**1,750**	**—**	**—**	**—**	**—**	**3,114**
Foreign exchange contracts - US dollar forwards - sell *(millions of US dollars)*	**3,140**	**5,853**	**3,784**	**1,856**	**648**	**—**	**15,281**
Foreign exchange contracts - British pound (GBP) forwards - sell *(millions of GBP)*	**67**	**28**	**29**	**30**	**30**	**60**	**244**
Foreign exchange contracts - Euro forwards - sell *(millions of Euro)*	**47**	**94**	**92**	**91**	**86**	**428**	**838**
Foreign exchange contracts - Japanese yen forwards - purchase *(millions of yen)*	**—**	**72,500**	**—**	**—**	**—**	**—**	**72,500**
Interest rate contracts - short-term debt pay fixed rate *(millions of Canadian dollars)*	**1,963**	**391**	**47**	**35**	**30**	**90**	**2,556**
Interest rate contracts - long-term debt pay fixed rate *(millions of Canadian dollars)*	**1,062**	**1,967**	**1,319**	**—**	**—**	**—**	**4,348**
Equity contracts *(millions of Canadian dollars)*	**39**	**7**	**11**	**—**	**—**	**—**	**57**
Commodity contracts - natural gas *(billions of cubic feet)*[2]	**81**	**48**	**12**	**4**	**11**	**—**	**156**
Commodity contracts - crude oil *(millions of barrels)*[2]	**13**	**—**	**—**	**—**	**—**	**—**	**13**
Commodity contracts - power *(megawatt per hour) (MW/H)*	**(41)**	**(43)**	**(43)**	**(43)**	**(43)**	**—**	**(43)** [1]

1 Total is an average net purchase/(sale) of power.
2 Total is a net purchase/(sale) of underlying commodity.

Fair Value Derivatives

For foreign exchange derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk is included in Net foreign currency gain/(loss) in the Consolidated Statements of Earnings. Any excluded components are included in the Consolidated Statements of Comprehensive Income.

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Unrealized gain/(loss) on derivative	**(32)**	(133)	**(35)**	85
Unrealized gain/(loss) on hedged item	**32**	138	**28**	(65)
Realized gain/(loss) on derivative	**—**	—	**(39)**	(12)
Realized gain on hedged item	**—**	—	**45**	—

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

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

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Amount of unrealized gain/(loss) recognized in OCI				
Cash flow hedges				
Foreign exchange contracts	**(5)**	(13)	**(25)**	6
Interest rate contracts	**(203)**	(35)	**294**	(750)
Commodity contracts	**4**	—	**(4)**	9
Other contracts	**1**	1	**4**	(6)
Fair value hedges				
Foreign exchange contracts	**(1)**	5	**(2)**	8
Net investment hedges				
Foreign exchange contracts	**—**	3	**—**	(4)
	(204)	(39)	**267**	(737)
Amount of loss reclassified from AOCI to earnings				
Foreign exchange contracts[1]	**2**	1	**3**	2
Interest rate contracts[2]	**79**	59	**142**	103
Commodity contracts	**(1)**	—	**—**	—
Other contracts[3]	**1**	—	**1**	—
	81	60	**146**	105

1 Reported within Transportation and other services revenues and Net foreign currency gain/(loss) in the Consolidated Statements of Earnings.
2 Reported within Interest expense in the Consolidated Statements of Earnings.
3 Reported within Operating and administrative expense in the Consolidated Statements of Earnings.

We estimate that a loss of $90 million of AOCI related to unrealized cash flow hedges will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the foreign exchange rates, interest rates and commodity prices in effect when derivative contracts that are currently outstanding mature. For all forecasted transactions, the maximum term over which we are hedging exposures to the variability of cash flows is 30 months as at June 30, 2021.

Non-Qualifying Derivatives

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

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Foreign exchange contracts[1]	**218**	1,246	**454**	(757)
Interest rate contracts[2]	**—**	3	**2**	(15)
Commodity contracts[3]	**(90)**	(517)	**(18)**	(44)
Other contracts[4]	**5**	—	**10**	(8)
Total unrealized derivative fair value gain/(loss), net	**133**	732	**448**	(824)

1 *For the respective six months ended periods, reported within Transportation and other services revenues (2021 - $292 million gain; 2020 - $437 million loss) and Net foreign currency gain/(loss) (2021 - $162 million gain; 2020 - $320 million loss) in the Consolidated Statements of Earnings.*

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

3 *For the respective six months ended periods, reported within Transportation and other services revenues (2021 - $3 million loss; 2020 - $17 million gain), Commodity sales (2021 - $144 million gain; 2020 - $403 million loss), Commodity costs (2021 - $166 million loss; 2020 - $348 million gain) and Operating and administrative expense (2021 - $7 million gain; 2020 - $6 million loss) in the Consolidated Statements of Earnings.*

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

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12-month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables ready access to either the Canadian or US public capital markets, subject to market conditions. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at June 30, 2021. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

CREDIT RISK

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

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

	June 30, 2021	December 31, 2020
(millions of Canadian dollars)		
Canadian financial institutions	**668**	481
US financial institutions	**230**	99
European financial institutions	**—**	28
Asian financial institutions	**245**	167
Other[1]	**110**	97
	1,253	872

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

As at June 30, 2021, we provided letters of credit totaling nil in lieu of providing cash collateral to our counterparties pursuant to the terms of the relevant International Swaps and Derivatives Association agreements. We held no cash collateral on derivative asset exposures as at June 30, 2021 and December 31, 2020.

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

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within Enbridge Gas Inc. (Enbridge Gas), credit risk is mitigated by the utility's large and diversified customer base and the ability to recover an estimate for 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 derivative instruments. We also disclose the fair value of other financial instruments not measured at fair value. The fair value of financial instruments reflects our best estimates of market value based on generally accepted valuation techniques or models and is supported by observable market prices and rates. When such values are not available, we use discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

Level 1

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

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

We have also categorized the fair value of our available-for-sale preferred share investment and long-term debt as Level 2. The fair value of our available-for-sale preferred share investment is based on the redemption value, which equals the face value plus accrued and unpaid interest periodically reset based on market interest rates. The fair value of our long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenor.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. We have developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates. Derivatives valued using Level 3 inputs primarily include long-dated derivative power, NGL and natural gas contracts, basis swaps, commodity swaps, and power and energy swaps. 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) as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread as well as the credit default swap spreads associated with our counterparties in our estimation of fair value.

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

June 30, 2021	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	**—**	**312**	**—**	**312**
Commodity contracts	**105**	**73**	**41**	**219**
Other contracts	**—**	**6**	**—**	**6**
	105	**391**	**41**	**537**
Long-term derivative assets				
Foreign exchange contracts	**—**	**493**	**—**	**493**
Interest rate contracts	**—**	**157**	**—**	**157**
Commodity contracts	**24**	**32**	**8**	**64**
Other contracts	**—**	**4**	**—**	**4**
	24	**686**	**8**	**718**
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	**—**	**(277)**	**—**	**(277)**
Interest rate contracts	**—**	**(156)**	**—**	**(156)**
Commodity contracts	**(123)**	**(69)**	**(173)**	**(365)**
	(123)	**(502)**	**(173)**	**(798)**
Long-term derivative liabilities				
Foreign exchange contracts	**—**	**(435)**	**—**	**(435)**
Interest rate contracts	**—**	**(146)**	**—**	**(146)**
Commodity contracts	**(28)**	**(16)**	**(54)**	**(98)**
	(28)	**(597)**	**(54)**	**(679)**
Total net financial assets/(liabilities)				
Foreign exchange contracts	**—**	**93**	**—**	**93**
Interest rate contracts	**—**	**(145)**	**—**	**(145)**
Commodity contracts	**(22)**	**20**	**(178)**	**(180)**
Other contracts	**—**	**10**	**—**	**10**
	(22)	**(22)**	**(178)**	**(222)**

December 31, 2020	Level 1	Level 2	Level 3	Total Gross Derivative Instruments
(millions of Canadian dollars)				
Financial assets				
Current derivative assets				
Foreign exchange contracts	—	180	—	180
Commodity contracts	43	33	67	143
	43	213	67	323
Long-term derivative assets				
Foreign exchange contracts	—	466	—	466
Interest rate contracts	—	56	—	56
Commodity contracts	1	24	14	39
	1	546	14	561
Financial liabilities				
Current derivative liabilities				
Foreign exchange contracts	—	(185)	—	(185)
Interest rate contracts	—	(425)	—	(425)
Commodity contracts	(39)	(18)	(223)	(280)
Other contracts	—	(4)	—	(4)
	(39)	(632)	(223)	(894)
Long-term derivative liabilities				
Foreign exchange contracts	—	(760)	—	(760)
Interest rate contracts	—	(241)	—	(241)
Commodity contracts	(1)	(8)	(49)	(58)
	(1)	(1,009)	(49)	(1,059)
Total net financial assets/(liabilities)				
Foreign exchange contracts	—	(299)	—	(299)
Interest rate contracts	—	(610)	—	(610)
Commodity contracts	4	31	(191)	(156)
Other contracts	—	(4)	—	(4)
	4	(882)	(191)	(1,069)

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

June 30, 2021	Fair Value	Unobservable Input	Minimum Price	Maximum Price	Weighted Average Price	Unit of Measurement
(fair value in millions of Canadian dollars)						
Commodity contracts - financial[1]						
Natural gas	**(9)**	**Forward gas price**	**2.83**	**5.90**	**3.87**	**$/mmbtu[2]**
Crude	**(17)**	**Forward crude price**	**67.09**	**90.65**	**75.20**	**$/barrel**
NGL	**—**	**Forward NGL price**	**0.99**	**1.39**	**1.37**	**$/gallon**
Power	**(49)**	**Forward power price**	**18.20**	**116.93**	**63.92**	**$/MW/H**
Commodity contracts - physical[1]						
Natural gas	**(17)**	**Forward gas price**	**2.43**	**6.75**	**4.02**	**$/mmbtu[2]**
Crude	**(86)**	**Forward crude price**	**67.19**	**91.39**	**85.53**	**$/barrel**
NGL	**—**	**Forward NGL price**	**—**	**—**	**—**	**$/gallon**
	(178)					

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

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of our Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments include forward commodity prices. Changes in forward commodity prices could result in significantly different fair values for our Level 3 derivatives.

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

	Six months ended June 30,	
	2021	2020
(millions of Canadian dollars)		
Level 3 net derivative liability at beginning of period	**(191)**	(69)
Total gain/(loss)		
Included in earnings[1]	**(143)**	(107)
Included in OCI	**(12)**	7
Settlements	**168**	41
Level 3 net derivative liability at end of period	**(178)**	(128)

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 June 30, 2021 or December 31, 2020.

NET INVESTMENT HEDGES

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

During the six months ended June 30, 2021 and 2020, we recognized an unrealized foreign exchange gain of $251 million and a loss of $371 million, respectively, on the translation of US dollar denominated debt and unrealized loss of nil and $4 million, respectively, on the change in fair value of our outstanding foreign exchange forward contracts in OCI. During the six months ended June 30, 2021 and 2020, we recognized no OCI associated with the settlement of foreign exchange forward contracts or with the settlement of US dollar denominated debt that had matured during the period.

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 $51 million and $52 million as at June 30, 2021 and December 31, 2020, respectively.

We have Restricted long-term investments held in trust totaling $573 million and $553 million as at June 30, 2021 and December 31, 2020, respectively, which are recognized at fair value.

During the three months ended June 30, 2021, we entered into a definitive agreement to sell our 38.9% noncontrolling interest in Noverco, which is comprised of both common shares and preferred shares. Historically, the preferred shares have been classified as held-to-maturity and carried at amortized cost. As a result of our intent to sell our interest in Noverco, the preferred shares were reclassified from held-to-maturity to available-for-sale at fair value during the second quarter of 2021. The fair value of the preferred shares was $580 million and $567 million as at June 30, 2021 and December 31, 2020, respectively. There were no gains or losses recognized in OCI on reclassification.

As at June 30, 2021 and December 31, 2020, our long-term debt had a carrying value of $67.1 billion and $66.1 billion, respectively, before debt issuance costs and a fair value of $74.0 billion and $75.1 billion, respectively. We also have non-current notes receivable carried at book value and recorded in Deferred amounts and other assets in the Consolidated Statements of Financial Position. As at June 30, 2021 and December 31, 2020, the non-current notes receivable had a carrying value of $1.0 billion and $1.1 billion, respectively, which also approximates their fair value.

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

10. INCOME TAXES

The effective income tax rates for the three months ended June 30, 2021 and 2020 were 15.1% and 25.0%, respectively and for the six months ended June 30, 2021 and 2020 were 17.6% and 9.2%, respectively.

The period-over-period change in the effective income tax rates is due to the effect of rate-regulated accounting for income taxes and the benefit of foreign tax rate differentials relative to the change in earnings being offset by a reduction in US minimum tax and the release of a previously recognized uncertain tax position as it has become statute barred.

11. PENSION AND OTHER POSTRETIREMENT BENEFITS

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Service cost	**48**	58	**96**	100
Interest cost	**32**	54	**64**	87
Expected return on plan assets	**(84)**	(113)	**(168)**	(180)
Amortization of actuarial loss and prior service costs	**14**	10	**28**	19
Net periodic benefit costs	**10**	9	**20**	26

For the three and six months ended June 30, 2020, we incurred $236 million in severance costs related to our voluntary workforce reduction program. For the three and six months ended June 30, 2021, there were no such costs incurred. Severance costs are included in Operating and administrative expense in the Consolidated Statements of Earnings.

12. CONTINGENCIES

We and our subsidiaries are involved in 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.

TAX MATTERS

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

ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

June 30, 2021

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

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our 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, 2020.

As of the end of the second quarter of 2021, we continue to qualify as a foreign private issuer for purposes of the United States Securities Exchange Act of 1934, as amended (Exchange Act). 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 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

COVID-19 PANDEMIC

In 2020, the COVID-19 pandemic had a significant negative impact on crude oil market fundamentals which resulted in elevated risks to our business and our customers. Global crude oil demand experienced an unprecedented drop in mid-2020, as the economy slowed and personal mobility decreased due to government restrictions. This, in turn, led to a decrease in crude oil throughput on our liquids pipelines systems as refinery runs decreased across North America.

There has since been a substantial recovery in oil demand as vaccination rates rise and economies continue to reopen. Crude oil prices have risen significantly since the 2020 collapse as the recovery in global demand has outpaced the return of crude oil supply. As of mid-year 2021, our Mainline System has returned to being substantially full, similar to before the impact of the pandemic, however, we continue to monitor economic and health risks.

We continue to follow recommendations from public health authorities and medical experts, which vary by jurisdiction, and to employ regular safety processes and procedures in the normal course. Where public health restrictions have allowed, we have begun implementing a phased return to workplace plan in certain of our office locations. Despite ongoing uncertainty as to the duration and impact of the pandemic and corresponding public health measures, our business continuity plans are designed to enable us to manage operational developments related to COVID-19 as they unfold, including those related to construction and integrity projects. We provide an essential service across North America. Our customers, and the communities where we operate, depend on us to safely and reliably provide the energy they need.

UNITED STATES LINE 3 REPLACEMENT PROGRAM

Construction of the United States (US) portion of the Line 3 Replacement Program (US L3R Program) in Minnesota continues to advance on schedule utilizing industry-leading environmental protection measures and construction techniques. On June 14, 2021, the Minnesota Court of Appeals affirmed the US L3R Program approvals. Several parties subsequently requested further review of this decision by the Minnesota Supreme Court. The project is progressing on schedule with an expected fourth quarter in-service date.

For additional regulatory updates on the project, refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.

CANADIAN MAINLINE SYSTEM CONTRACTING

On December 19, 2019, we submitted an application to the Canada Energy Regulator (CER) to implement contracting on our Canadian Mainline System. The application for contracted and uncommitted service included the associated terms, conditions and tolls of each service, which would be offered in an open season following approval by the CER.

Procedural steps with all participants before the CER are now complete. A decision by the CER is expected later this year.

In accordance with the terms of the Competitive Tolling Settlement (CTS), which expired on June 30, 2021, the tolls in place on June 30, 2021, will continue on an interim basis, subject to finalization and adjustment applicable to the interim period, if any.

GAS TRANSMISSION AND MIDSTREAM RATE PROCEEDINGS

Texas Eastern Transmission
Texas Eastern Transmission, LP (Texas Eastern) intends to file a rate case in the third quarter of 2021 and expects to commence settlement discussions with shippers in the fourth quarter of 2021.

East Tennessee
East Tennessee Natural Gas, LLC (ETNG) filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in April 2021. A Stipulation and Agreement was filed on May 21, 2021, and we await Federal Energy Regulatory Commission (FERC) approval.

Maritimes & Northeast Pipeline
The US portion of Maritimes & Northeast Pipeline filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in December 2020. A Stipulation and Agreement was filed on February 21, 2021, approved by the FERC on April 30, 2021, and was effective on June 1, 2021.

Alliance Pipeline
The US portion of Alliance Pipeline filed a rate case in the second quarter of 2020 and an agreement in principle was reached with shippers in January 2021. A Stipulation and Agreement was filed on March 31, 2021, approved by the FERC on July 15, 2021, and is expected to be effective on September 1, 2021.

GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS

2021 Rate Application

On June 30, 2020, Enbridge Gas Inc. (Enbridge Gas) filed Phase 1 of an application with the Ontario Energy Board (OEB) for the setting of rates for 2021. The 2021 rate application was filed in accordance with the parameters of Enbridge Gas's OEB approved Price Cap Incentive Regulation (IR) rate setting mechanism and represents the third year of a five-year term. On November 6, 2020, as part of its Decision on Settlement Proposal and Interim Rate Order, the OEB approved Enbridge Gas's Phase 1 Settlement Proposal and interim rates, effective January 1, 2021. On May 6, 2021, the OEB issued its decision on Phase 2 of Enbridge Gas's application filed on October 15, 2020, addressing 2021 incremental capital module funding requirements, under which $124 million of Enbridge Gas requested capital funding was approved.

2022 Rate Application

On June 30, 2021, Enbridge Gas filed Phase 1 of an application with the OEB for the setting of rates for 2022. The 2022 rate application was filed in accordance with the parameters of Enbridge Gas OEB approved Price Cap IR rate setting mechanism and represents the fourth year of a five-year term. An OEB decision on Phase 1 of the application is expected in the second half of 2021.

SOLAR SELF-POWER PROJECTS

Alberta Solar One

In March 2021, we commenced commercial operations on our first self-powering solar generation facility in Alberta. The 10.5-megawatts (MW) solar project, located near Burdett, Alberta, will supply a portion of our Canadian Mainline power requirements with solar energy.

Heidlersburg Solar Project

On May 15, 2021, a 2.5 MW self-power facility, located at the Heidlersburg compressor station on the Texas Eastern system, was placed into service.

We now have three operating solar self-power facilities. An additional four projects, with a combined 35 MW of generation, are under development and expected to enter service in late 2022.

FINANCING UPDATE

On February 10, 2021, we entered into a three year, revolving, extendible, sustainability-linked credit facility for $1.0 billion with a syndicate of lenders. We concurrently cancelled a one year, revolving, syndicated credit facility for $3.0 billion, ahead of its scheduled March 2021 maturity.

On February 19, 2021, we closed our inaugural US$500 million two-year Secured Overnight Financing Rate (SOFR) based Floating Rate Note (FRN) offering. The transaction has been reported to be the first SOFR-linked FRN offering by a non-financial issuer in the global fixed income market. Proceeds of this offering were used for repayment of two United States dollars (USD) term loans for the equivalent aggregate amount which matured on February 25, 2021.

On May 12, 2021, Enbridge Pipelines Inc. closed an $800 million dual-tranche medium-term notes offering in the Canadian public debt market, split evenly between 10 and 30-year tranches. Proceeds of this offering were used to repay short-term debt, for capital expenditures and for general corporate purposes.

On June 28, 2021, we closed a dual-tranche debt offering consisting of an inaugural US$1.0 billion 12-year Sustainability-Linked senior notes issuance and a US$500 million 30-year senior note issuance. The Sustainability-Linked senior notes follow the guidance of our recently published Sustainability-Linked Bond Framework by incorporating greenhouse gas emissions intensity reduction and workforce diversity sustainability performance targets (SPTs) into the financing terms. If the SPTs are not met, the interest rate on the Sustainability-Linked senior notes will increase, helping to align our funding strategies with our environmental, social and governance ambitions. The proceeds from the issuance were used to repay existing indebtedness, partially fund capital projects and for other general corporate purposes.

On July 22 and 23, 2021, we renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

These financing activities, in combination with the financing activities executed in 2020, are expected to provide significant liquidity and to enable us to fund our current portfolio of capital projects without requiring access to the capital markets for the next 12 months if market access is restricted or pricing is unattractive. Refer to *Liquidity and Capital Resources*.

Credit Rating Action
On June 1, 2021, Moody's Investors Service (Moody's) upgraded the credit ratings of Enbridge Inc. including our senior unsecured and issuer ratings to Baa1 from Baa2. Moody's also upgraded the credit ratings of our subsidiaries: Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Limited Partnership (EELP), Spectra Energy Partners, LP (SEP) and Texas Eastern. The outlooks of all five entities are stable.

ASSET MONETIZATION

Éolien Maritime France SAS
On March 18, 2021, we sold 49% of an entity that holds our 50% interest in Éolien Maritime France SAS (EMF) to the Canada Pension Plan Investment Board (CPP Investments). CPP Investments will fund their 49% share of all ongoing future development capital. Through our investment in EMF, we own equity interests in three French offshore wind projects, including Saint-Nazaire (25.5%), Fécamp (17.9%) and Calvados (21.7%). The Calvados Offshore Wind Project reached a positive final investment decision in February 2021 and all three projects are now considered commercially secured.

Noverco Inc.
On June 7, 2021, we entered into a definitive agreement to sell our 38.9% non-operating minority ownership interest in Noverco Inc. (Noverco) to Trencap L.P. for $1.14 billion in cash, subject to purchase price adjustments. Closing of the transaction is expected to occur by early 2022 and is subject to the receipt of regulatory approvals and customary closing conditions.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this 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; the COVID-19 pandemic and the duration and impact thereof; energy intensity and emissions reduction targets and related environment, social and governance matters; diversity and inclusion goals; expected supply of, demand for and prices of crude oil, natural gas, natural gas liquids (NGL), liquified natural gas (LNG) and renewable energy; energy transition; anticipated utilization of our existing assets; expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows and distributable cash flow; 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 and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction and for maintenance; expected capital expenditures, investment capacity and capital allocation priorities; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and the timing thereof; expected benefits of transactions, including the realization of efficiencies, synergies and cost savings; expected future actions of regulators and courts; toll and rate cases discussions and filings, including Mainline System contracting; anticipated competition; US Line 3 Replacement Program (US L3R Program), including anticipated in-service dates and capital costs; and Line 5 dual pipelines and related litigation and other matters.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the COVID-19 pandemic and the duration and impact thereof; the expected supply of and demand for crude oil, natural gas, NGL and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; anticipated utilization of assets; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of acquisitions and dispositions; the realization of anticipated benefits and synergies 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 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 and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates and the COVID-19 pandemic impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected EBITDA, expected earnings/(loss), expected future cash flows, expected distributable cash flow or estimated future dividends. The most relevant assumptions associated with forward-looking statements regarding announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government, court and regulatory approvals on construction and in-service schedules and cost recovery regimes; and the COVID-19 pandemic and the duration and impact thereof.

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, including with respect to the US L3R Program, Dakota Access Pipeline (DAPL) and Line 5 dual pipelines; acquisitions, dispositions and other transactions and the realization of anticipated benefits therefrom; our dividend policy; project approval and support; renewals of rights-of-way; weather; economic and competitive conditions; public opinion; changes in tax laws and tax rates; exchange rates; interest rates; commodity prices; political decisions; the supply of, demand for and prices of commodities; and the COVID-19 pandemic, 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 risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge assumes no obligation to publicly update or revise any forward-looking statement 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.

RESULTS OF OPERATIONS

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars, except per share amounts)				
Segment earnings/(loss) before interest, income taxes and depreciation and amortization				
Liquids Pipelines	**2,044**	2,340	**4,083**	3,190
Gas Transmission and Midstream	**868**	950	**1,841**	(104)
Gas Distribution and Storage	**458**	383	**1,092**	987
Renewable Power Generation	**115**	163	**271**	283
Energy Services	**(239)**	(99)	**(175)**	22
Eliminations and Other	**92**	261	**312**	(705)
Earnings before interest, income taxes and depreciation and amortization	**3,338**	3,998	**7,424**	3,673
Depreciation and amortization	**(929)**	(949)	**(1,861)**	(1,831)
Interest expense	**(618)**	(681)	**(1,275)**	(1,387)
Income tax expense	**(270)**	(591)	**(753)**	(42)
Earnings attributable to noncontrolling interests	**(37)**	(36)	**(59)**	(5)
Preference share dividends	**(90)**	(94)	**(182)**	(190)
Earnings attributable to common shareholders	**1,394**	1,647	**3,294**	218
Earnings per common share attributable to common shareholders	**0.69**	0.82	**1.63**	0.11
Diluted earnings per common share attributable to common shareholders	**0.69**	0.82	**1.63**	0.11

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Three months ended June 30, 2021, compared with the three months ended June 30, 2020

Earnings attributable to common shareholders were negatively impacted by $477 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following factors:

- a non-cash, unrealized derivative fair value gain of $242 million ($185 million after-tax) in 2021, compared with a gain of $1.2 billion ($876 million after-tax) in 2020, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks; and
- the absence in 2021 of a non-cash, net positive adjustment to crude oil and natural gas inventories in our Energy Services business segment of $340 million ($257 million after-tax) in 2020.

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

- a non-cash, unrealized loss of $153 million ($117 million after-tax) in 2021, compared with an unrealized loss of $525 million ($397 million after-tax) in 2020, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices; and
- employee severance, transition and transformation costs of $36 million ($28 million after-tax) in 2021, compared with $268 million ($200 million after-tax) in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020.

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

After taking into consideration the factors above, the remaining $224 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to increased volumes and a higher International Joint Tariff (IJT) Benchmark Toll;
- increased earnings from our Gas Distribution and Storage segment due to higher distribution charges resulting from increases in rates and customer base;
- increased earnings from new assets being placed into service, including: the Atlantic Bridge Phase III project in our Gas Transmission and Midstream segment (with in-service notification to FERC in January of 2021), and the Woodland Pipeline Expansion project in our Liquids Pipelines segment (placed into service in June of 2021);
- lower interest expense primarily due to lower rates; and
- lower income tax expense primarily due to decreased earnings and a reduction in US minimum tax.

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

- decreased earnings from our Energy Services segment due to the significant compression of location and quality differentials in certain markets, fewer storage opportunities due to market backwardation and fewer opportunities to achieve profitable transportation margins on facilities where we hold capacity obligations; and
- decreased earnings from our Liquids Pipelines and Gas Transmission and Midstream segments due to the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 compared to the same period in 2020, partially offset by increased revenues due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020.

Six months ended June 30, 2021, compared with the six months ended June 30, 2020

Earnings attributable to common shareholders were positively impacted by $2.9 billion due to certain unusual, infrequent or other non-operating factors, primarily explained by the following factors:

- a non-cash, unrealized derivative fair value gain of $521 million ($396 million after-tax) in 2021, compared with a loss of $770 million ($585 million after-tax) in 2020, reflecting changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks;
- employee severance, transition and transformation costs of $72 million ($55 million after-tax) in 2021, compared to $279 million ($212 million after-tax) in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020;
- the absence in 2021 of a non-cash impairment to the carrying value of our investment in DCP Midstream, LLC (DCP Midstream) of $1.7 billion ($1.3 billion after-tax) recognized in 2020;
- the absence in 2021 of a loss of $324 million ($244 million after-tax) resulting from asset and goodwill impairment losses within DCP Midstream recognized in 2020; and
- the absence in 2021 of a loss of $159 million ($119 million after-tax) in 2020 resulting from the Texas Eastern rate case settlement that re-established the Excess Accumulated Deferred Income Tax (EDIT) regulated liability that was previously eliminated in December 2018.

After taking into consideration the factors above, the remaining $190 million increase in earnings attributable to common shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to a higher IJT Benchmark Toll;
- increased earnings from our Gas Distribution and Storage segment due to higher distribution charges resulting from increases in rates and customer base;
- increased earnings from new assets being placed into service, including: the Atlantic Bridge Phase III project in our Gas Transmission and Midstream segment (with in-service notification to FERC in January of 2021), and the Woodland Pipeline Expansion project in our Liquids Pipelines segment (placed into service in June of 2021); and
- lower interest expense primarily due to lower rates.

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

- decreased earnings from our Energy Services segment due to the significant compression of location and quality differentials in certain markets, fewer storage opportunities due to market backwardation, adverse impacts from the major winter storm experienced across the US Midwest during February 2021 and fewer opportunities to achieve profitable transportation margins on facilities in which Energy Services holds capacity obligations;
- decreased earnings from our Liquids Pipelines and Gas Transmission and Midstream segments due to the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 compared to the same period in 2020;
- the absence in 2021 of the recognition of revenues in 2020 from a rate settlement on Texas Eastern, partially offset by increased revenues due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- higher income tax expense primarily due to increased earnings, partially offset by a reduction in US minimum tax.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**2,044**	2,340	**4,083**	3,190

Three months ended June 30, 2021, compared with the three months ended June 30, 2020

EBITDA was negatively impacted by $396 million due to certain infrequent or other non-operating factors, primarily explained by non-cash, unrealized gains of $145 million in 2021, compared with unrealized gains of $616 million in 2020, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks. The decrease in mark-to-market gains was partially offset by a property tax settlement of $57 million related to the resolution of Minnesota property tax appeals for 2012-2018.

After taking into consideration the factors above, the remaining $100 million increase is primarily explained by the following significant business factors:

- higher Mainline System ex-Gretna throughput of 2.6 million barrels per day (mmbpd) in 2021 compared with 2.4 mmbpd in 2020 driven by the rebounding demand for crude oil and related products as economies continue to recover from the impacts of the COVID-19 pandemic;
- a higher IJT Benchmark Toll on our Mainline System of US$4.27 in 2021, compared with US$4.21 in 2020;

- a higher foreign exchange hedge rate used to lock-in US dollar denominated Canadian Mainline revenue;
- an increased CTS surcharge of US$0.11 per barrel in 2021, compared to US$0.005 per barrel in 2020;
- higher throughput on our Athabasca and Waupisoo pipelines as production in the basin recovers from its lowest point in the second quarter of 2020; and
- stronger contributions on our Seaway Crude Pipeline System.

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

- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 compared with 2020; and
- lower throughput on our Flanagan South Pipeline (Flanagan South) as a result of robust refinery demand in PADD II resulting in less volumes available to move towards the US Gulf Coast.

Six months ended June 30, 2021, compared with the six months ended June 30, 2020

EBITDA was positively impacted by $831 million due to certain infrequent or other non-operating factors, primarily explained by the following:

- non-cash, unrealized gains of $306 million in 2021, compared with unrealized losses of $450 million in 2020, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange risks; and
- a property tax settlement of $57 million related to the resolution of Minnesota property tax appeals for 2012-2018.

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

- a higher IJT Benchmark Toll on our Mainline System of US$4.27 in 2021, compared with US$4.21 in 2020;
- a higher foreign exchange hedge rate used to lock-in US dollar denominated Canadian Mainline revenue;
- an increased CTS surcharge of US$0.11 per barrel in 2021, compared to US$0.005 per barrel in 2020;
- higher throughput on our Athabasca and Waupisoo pipelines as production in the basin recovers from its lowest point in the second quarter of 2020; and
- stronger contributions on our Seaway Crude Pipeline System.

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

- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021, compared with the same period in 2020; and
- lower throughput on our Flanagan South as a result of robust refinery demand in PADD II resulting in less volumes available to move towards the US Gulf Coast.

GAS TRANSMISSION AND MIDSTREAM

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**868**	950	**1,841**	(104)

Three months ended June 30, 2021, compared with the three months ended June 30, 2020

EBITDA was negatively impacted by $42 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, negative equity earnings adjustment of $47 million in 2021, compared with a net negative adjustment of $22 million in 2020 relating to changes in the mark-to-market value of derivative financial instruments of our equity method investee, DCP Midstream.

After taking into consideration the factors above, the remaining $40 million decrease is primarily explained by the following significant business factors:

- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021, compared to the same period in 2020; and
- the absence in 2021 of the recognition of revenues in 2020 that related to the settlement of interim rates collected from shippers on Texas Eastern, retroactive to June 1, 2019.

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

- increased revenue on our US Gas Transmission assets due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- contributions from the Atlantic Bridge Phase III project with in-service notification to FERC in January 2021.

Six months ended June 30, 2021, compared with the six months ended June 30, 2020

EBITDA was positively impacted by $2.1 billion due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- the absence in 2021 of a non-cash impairment to the carrying value of our investment in DCP Midstream of $1.7 billion recognized in 2020;
- the absence in 2021 of a loss of $324 million resulting from asset and goodwill impairment losses within DCP Midstream recognized in 2020;
- the absence in 2021 of a loss of $159 million in 2020 resulting from the Texas Eastern rate case settlement that re-established the EDIT regulated liability that was previously eliminated in December 2018; and
- a non-cash, negative equity earnings adjustment of $66 million in 2021, compared with a positive adjustment of $31 million in 2020 relating to changes in the mark-to-market value of derivative financial instruments of our equity method investee, DCP Midstream which partially offset the positive factors above.

After taking into consideration the factors above, the remaining $130 million decrease is primarily explained by the following significant business factors:

- the net unfavorable effect of translating US dollar EBITDA at a lower Canadian to US dollar average exchange rate in 2021, compared to the same period in 2020; and
- the absence in 2021 of the recognition of revenues in 2020 that related to the settlement of interim rates collected from shippers on Texas Eastern, retroactive to June 1, 2019.

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

- increased revenue on our US Gas Transmission assets due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- contributions from the Atlantic Bridge Phase III project with in-service notification to FERC in January 2021.

GAS DISTRIBUTION AND STORAGE

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**458**	383	**1,092**	987

Three months ended June 30, 2021, compared with the three months ended June 30, 2020

EBITDA was positively impacted by $20 million due to certain unusual, infrequent and other non-operating factors, primarily explained by a non-cash, unrealized gain of $12 million in 2021, compared with an unrealized loss of $15 million in 2020 arising from the change in the mark-to-market value of Noverco's derivative financial instruments. This positive factor was partially offset by employee transition and transformation costs of $14 million in 2021, compared to $8 million in 2020.

After taking into consideration the factor above, the remaining $55 million increase is primarily explained by the following business factors:

- lower operating and administrative expenses, largely due to achieved efficiencies; and
- higher distribution charges resulting from increases in rates and customer base growth.

The positive business factors above were partially offset by the effect of weather experienced in our service area. When compared with the normal weather forecast embedded in rates, 2021 had a negligible impact to 2021 EBITDA while the colder than normal weather in 2020 positively impacted 2020 EBITDA by approximately $22 million.

Six months ended June 30, 2021, compared with the six months ended June 30, 2020

EBITDA was positively impacted by $13 million due to certain unusual, infrequent and other non-operating factors, primarily explained by a non-cash, unrealized gain of $14 million in 2021, compared with an unrealized loss of $9 million in 2020 arising from the change in the mark-to-market value of Noverco's derivative financial instruments. This positive factor was partially offset by employee transition and transformation costs of $28 million in 2021, compared to $15 million in 2020.

After taking into consideration the factor above, the remaining $92 million increase is primarily explained by the following business factors:

- higher distribution charges resulting from increases in rates and customer base growth;
- higher optimization revenue, mainly relating to our storage assets; and
- lower operating and administrative expenses, largely due to achieved efficiencies.

RENEWABLE POWER GENERATION

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Earnings before interest, income taxes and depreciation and amortization	**115**	163	**271**	283

Three months ended June 30, 2021, compared with the three months ended June 30, 2020

EBITDA was negatively impacted by $11 million due to certain unusual, infrequent and other non-operating factors, primarily explained by an absence in 2021 of a gain of $4 million on disposal and a $9 million further revision to the fair value of our Montana-Alberta Tie Line (MATL) transmission assets in 2020.

After taking into consideration the factor above, the remaining $37 million decrease is primarily explained by the following business factors:

- the absence in 2021 of reimbursements received in 2020 at certain Canadian wind facilities resulting from a change in operator; and
- weaker wind resources at Canadian wind facilities.

Six months ended June 30, 2021, compared with the six months ended June 30, 2020

EBITDA was negatively impacted by $11 million due to certain unusual, infrequent and other non-operating factors, primarily explained by an absence in 2021 of a gain of $4 million on disposal and a $9 million further revision to the fair value of our MATL transmission assets in 2020.

After taking into consideration the factor above, the remaining $1 million decrease is primarily explained by the following business factors:

- weaker wind resources at the Canadian and US wind facilities and the effects from the winter storm in Texas during February 2021; and
- the absence in 2021 of reimbursements received in 2020 at certain Canadian wind facilities resulting from a change in operator.

The business factors above were partially offset by the sale of a 49% interest of an entity that holds our 50% interest in EMF.

ENERGY SERVICES

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**(239)**	(99)	**(175)**	22

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

Three months ended June 30, 2021, compared with the three months ended June 30, 2020

EBITDA was positively impacted by $32 million due to certain non-operating factors, explained by a non-cash, unrealized loss of $153 million in 2021, compared with a loss of $525 million in 2020, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices. This positive factor was offset by the absence in 2021 of a net positive adjustment to crude oil and natural gas inventories of $340 million in 2020.

After taking into consideration the factors above, the remaining $172 million decrease is primarily explained by the following significant factors:

- the significant compression of location and quality differentials in certain markets;
- limited storage opportunities in 2021 due to market backwardation compared to favorable storage opportunities in 2020; and
- fewer opportunities to achieve profitable transportation margins on facilities in which Energy Services holds capacity obligations.

Six months ended June 30, 2021, compared with the six months ended June 30, 2020

EBITDA was positively impacted by $37 million due primarily to a non-operating, non-cash, unrealized loss of $14 million in 2021, compared with a loss of $49 million in 2020, reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions, as well as manage the exposure to movements in commodity prices.

After taking into consideration the factors above, the remaining $234 million decrease is primarily explained by the following significant factors:

- significant compression of location and quality differentials in certain markets;
- limited storage opportunities in 2021 due to market backwardation compared to favorable storage opportunities in 2020;
- fewer opportunities to achieve profitable transportation margins on facilities in which Energy Services holds capacity obligations; and
- adverse impacts from the major winter storm experienced across the US Midwest during February 2021.

ELIMINATIONS AND OTHER

	Three months ended June 30,		Six months ended June 30,	
	2021	2020	**2021**	2020
(millions of Canadian dollars)				
Earnings/(loss) before interest, income taxes and depreciation and amortization	**92**	261	**312**	(705)

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

Three months ended June 30, 2021, compared with the three months ended June 30, 2020

EBITDA was negatively impacted by $253 million due to certain unusual, infrequent and other non-operating factors, primarily explained a non-cash, unrealized gain of $83 million in 2021, compared with an unrealized gain of $585 million in 2020, reflecting the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk.

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

- employee severance, transition and transformation costs of $20 million in 2021, compared to $253 million in 2020 primarily related to our voluntary workforce reduction program offered in the second quarter of 2020; and
- a non-cash, unrealized intercompany foreign exchange loss of $3 million in 2021, compared to $22 million in 2020.

After taking into consideration the non-operating factors above, the remaining $84 million increase is primarily explained by realized gains related to settlements under our enterprise-wide foreign exchange risk management program which substantially offset the foreign currency exposures realized within our business segments' results. This factor was partially offset by the timing of the recovery of certain operating administrative costs allocated to the business segments.

Six months ended June 30, 2021, compared with the six months ended June 30, 2020

EBITDA was positively impacted by $836 million due to certain unusual, infrequent and other non-operating factors, primarily explained by the following:

- a non-cash, unrealized gain of $197 million in 2021, compared with an unrealized loss of $313 million in 2020, reflecting the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- employee severance, transition and transformation costs of $39 million in 2021, compared to $257 million in 2020;
- the absence in 2021 of a loss of $74 million in 2020 from non-cash changes in a corporate guarantee obligation; and
- the absence in 2021 of a loss of $43 million in 2020 from the write-down of certain minor investments in emerging energy and other technologies.

After taking into consideration the non-operating factors above, the remaining $181 million increase is primarily explained by realized gains related to settlements under our enterprise-wide foreign exchange risk management program which substantially offset the foreign currency exposures realized within our business segments' results. This factor was partially offset by the timing of the recovery of certain operating administrative costs allocated to the business segments.

GROWTH PROJECTS – COMMERCIALLY SECURED PROJECTS

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

	Enbridge's Ownership Interest	Estimated Capital Cost[1]	Expenditures to Date[2]	Status	Expected In-Service Date
(Canadian dollars, unless stated otherwise)					
LIQUIDS PIPELINES					
1. US Line 3 Replacement Program	100 %	US$4.0 billion	US$3.1 billion	Under construction	Q4 - 2021
2. Southern Access Expansion[3]	100 %	US$0.5 billion	US$0.5 billion	Under construction	Q4 - 2021
3. Other - US	100 %	US$0.1 billion	US$0.1 billion	Under construction	Q3 - 2021
GAS TRANSMISSION AND MIDSTREAM					
4. T-South Reliability & Expansion Program	100 %	$1.0 billion	$0.8 billion	Under construction	Q4 - 2021
5. Spruce Ridge Project	100 %	$0.5 billion	$0.3 billion	Under construction	Q4 - 2021
6. Other - US	Various	US$0.8 billion	US$0.4 billion	Various stages	2021 - 2023
GAS DISTRIBUTION AND STORAGE					
7. System Enhancement Projects	100 %	$0.3 billion	No significant expenditures to date	Various stages	2021 - 2022
8. Storage Enhancements	100 %	$0.1 billion	No significant expenditures to date	Under construction	2021 - 2022
9. Community Expansion Program[4]	100 %	$0.1 billion	No significant expenditures to date	Pre-construction	2022 - 2027
RENEWABLE POWER GENERATION					
10. East-West Tie Line	25.0 %	$0.2 billion	$0.1 billion	Under construction	1H - 2022
11. Solar Self-Power Projects[5]	100 %	US$0.1 billion	No significant expenditures to date	Various stages	2H - 2022
12. Saint-Nazaire France Offshore Wind Project[6]	25.5 %	$0.9 billion (€0.6 billion)	$0.4 billion (€0.2 billion)	Under construction	2H - 2022
13. Fécamp Offshore Wind Project[7]	17.9 %	$0.7 billion (€0.5 billion)	$0.2 billion (€0.1 billion)	Under construction	2023
14. Calvados Offshore Wind Project[8]	21.7 %	$0.9 billion (€0.6 billion)	No significant expenditures to date	Under construction	2024

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

2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project to June 30, 2021.

3 The status and in-service date will coincide with the status and in-service date of the US L3R Program.

4 Represents Phase 2 of the Natural Gas Expansion Program (the Program) and the estimated capital cost is presented net of the maximum funding assistance we expect to receive from the Government of Ontario. The expected in-service dates represent the expected completion dates of the leave to construct requirements.

5 Self-Power Projects consists of four solar projects along our US Mainline and Flanagan South liquids systems. All four will be located at existing pump stations—Adams (6.9 MW), Vesper (8.8 MW) and Portage (8 MW) in central Wisconsin, and Flanagan (10 MW) in north-central Illinois.
6 Reflects the sale of 49% of an entity that holds our 50% interest in EMF to CPP Investments that closed in the first quarter of 2021. Our equity contribution is $0.15 billion, with the remainder of the project financed through non-recourse project level debt.
7 Reflects the sale of 49% of an entity that holds our 50% interest in EMF to CPP Investments that closed in the first quarter of 2021. Our equity contribution is $0.1 billion, with the remainder of the project financed through non-recourse project level debt.
8 Reflects the sale of 49% of an entity that holds our 50% interest in EMF to CPP Investments that closed in the first quarter of 2021. Our equity contribution is $0.1 billion, with the remainder of the project financed through non-recourse project level debt

A full description of each of our projects is provided in our annual report on Form 10-K for the year ended December 31, 2020. Significant updates that have occurred since the date of filing of our Form 10-K are discussed below.

GAS DISTRIBUTION AND STORAGE

- **System Enhancement Projects** – Consists of the London Line Replacement Project and the Lake Shore KOL Replacement Project. The London Line Replacement Project will replace the two current pipelines known collectively as the London Line and includes the construction of approximately 90.5-kilometers of natural gas pipeline and ancillary facilities in southern Ontario. The project is expected to be placed into service in the fourth quarter of 2021. The Lake Shore KOL Replacement Project is a replacement of approximately 4.5-kilometers of natural gas pipeline and ancillary facilities of the Cherry to Bathurst segment of the Kipling Oshawa Loop (KOL) along Lake Shore Boulevard in the City of Toronto. The project is expected to be placed into service in the second half of 2022.

- **Community Expansion Program** – The Program was created under the *Access to Natural Gas Act, 2018* to help expand access to natural gas to areas of Ontario that currently do not have access to the natural gas distribution system. Funding assistance was approved for Enbridge Gas under Phase 1 of the Program. To date, Enbridge Gas has initiated five of the projects approved for funding under the Program, with continued progress through 2021. On June 8, 2021, the Government of Ontario approved additional funding for projects under Phase 2 of the Program, under which Enbridge Gas will be provided up to $214 million in funding assistance to deliver 27 expansion projects throughout Ontario.

RENEWABLE POWER GENERATION

- **Solar Self-Power Projects** – Phase 1 of the project is comprised of four solar projects co-located at existing pump stations with behind-the-meter interconnections. The projects are expected to support our emissions reduction goals and are expected to be placed into service in the second half of 2022.

- **Calvados Offshore Wind Project** – an offshore wind project located off the northwest coast of France that is expected to generate approximately 448 MW. Project revenues are underpinned by a 20-year fixed price power purchase agreement.

During the first quarter of 2021, we sold 49% of an entity that holds our 50% interest in EMF to CPP Investments. EMF holds equity interests in the Fécamp Offshore Wind Project, the Saint-Nazaire France Offshore Wind Project and the Calvados Offshore Wind Project. CPP Investments will fund their 49% share of all ongoing future development capital.

GROWTH PROJECTS - REGULATORY MATTERS

United States Line 3 Replacement Program
On February 3, 2020, and through its subsequent order on May 1, 2020, the Minnesota Public Utilities Commission (MNPUC) deemed the second revised final Environmental Impact Statement (EIS) for the US L3R Program adequate and reinstated the Certificate of Need and Route Permit, allowing for construction of the pipeline to commence following the issuance of required permits. After each environmental permitting agency issued their respective permits, the MNPUC issued its Authorization to Construct to Enbridge. With all required permits received, we commenced construction on December 1, 2020. Actions for injunctive relief at state and federal levels against the project have failed or have been denied to date. On June 14, 2021, based on subsequent consolidated appeals of the EIS, Certificate of Need and Route Permit, the Minnesota Court of Appeals affirmed the MNPUC's determinations for the US L3R Program. On July 14, 2021, several parties sought further review of this decision by the Minnesota Supreme Court. Currently, construction in Minnesota continues despite ongoing appellate review; however, judicial decisions may impact construction activities.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

We have announced the following projects, but neither have met our criteria to be classified as commercially secured:

GAS TRANSMISSION AND MIDSTREAM

- **Rio Bravo Pipeline** – The Rio Bravo Pipeline is designed to transport up to 4.5 billion cubic feet per day of natural gas from the Agua Dulce supply area to NextDecade's Rio Grande LNG export facility in the Port of Brownsville, Texas. We have acquired the Rio Bravo Pipeline development project from NextDecade. In addition, we have executed a precedent agreement with NextDecade under which we will provide firm transportation capacity on the Rio Bravo Pipeline to NextDecade's Rio Grande LNG export facility for a term of at least 20 years. Construction of the pipeline will be subject to the Rio Grande LNG export facility reaching a final investment decision which is forecasted to occur in the second half of 2021.

- **Ridgeline Expansion Project Opportunity** – We are working on a potential expansion of the ETNG system which would provide additional natural gas for the Tennessee Valley Authority (TVA) to support the replacement of an existing coal-fired power plant as it continues to transition its generation mix towards lower-carbon fuels. The TVA environmental review scoping process has begun for this proposed plant; TVA published a Notice of Intent (NOI) on the Federal Register on June 15, 2021 to initiate their review process. Several options to replace the retiring coal-fired generation would be assessed in TVA's EIS. Should the onsite natural gas option of building a combined cycle plant be selected through TVA's review, we would deliver on the required expansion of the East Tennessee system. ETNG's proposed project would consist of the installation of additional pipeline primarily along the ETNG system, the installation of one electric-powered compressor station and solar facilities behind the meter, as well as other design features all contributing to minimizing greenhouse gas emissions. Should TVA's environmental assessment determine that the natural gas solution of building an onsite combined cycle plant is the optimal supply source, and pending the approval and receipt of all necessary permits, construction of the pipeline would begin in 2025 with a target in-service date of fall 2026.

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

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 issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives. Our current financing plan does not include any issuances of additional common equity.

CAPITAL MARKET ACCESS

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

Credit Facilities and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities as at June 30, 2021:

	Maturity[1]	Total Facilities	Draws[2]	Available
(millions of Canadian dollars)				
Enbridge Inc.	2022-2024	**9,125**	**7,446**	**1,679**
Enbridge (U.S.) Inc.	2022-2024	**6,811**	**3,076**	**3,735**
Enbridge Pipelines Inc.	2022	**3,000**	**494**	**2,506**
Enbridge Gas Inc.	2022	**2,000**	**1,410**	**590**
Total committed credit facilities		**20,936**	**12,426**	**8,510**

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.

On February 10, 2021, Enbridge Inc. entered into a three year, revolving, extendible, sustainability-linked credit facility for $1.0 billion with a syndicate of lenders and concurrently terminated our one year, revolving, syndicated credit facility for $3.0 billion.

On February 25, 2021, two term loans with an aggregate total of US$500 million were repaid with proceeds from a floating rate notes issuance.

On July 22 and 23, 2021, we renewed approximately $8.0 billion of our five-year credit facilities, extending the maturity date out to July 2026. We also extended approximately $10.0 billion of our 364-day extendible credit facilities to July 2022, which includes a one-year term out provision to July 2023.

In addition to the committed credit facilities noted above, we maintain $1.4 billion of uncommitted demand credit facilities, of which $978 million was unutilized as at June 30, 2021. As at December 31, 2020, we had $849 million of uncommitted demand credit facilities, of which $533 million was unutilized.

Our net available liquidity of $8.9 billion as at June 30, 2021, was inclusive of $374 million of unrestricted cash and cash equivalents as reported in the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at June 30, 2021, we were in compliance with all debt covenants and we expect to continue to comply with such covenants.

LONG-TERM DEBT ISSUANCES

During the six months ended June 30, 2021, we completed the following long-term debt issuances totaling US$2.0 billion and $800 million:

Company	Issue Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	Floating rate notes due February 2023[1]	US$500
	June 2021	2.50% Sustainability-Linked senior notes due August 2033	US$1,000
	June 2021	3.40% senior notes due August 2051	US$500
Enbridge Pipelines Inc.			
	May 2021	4.20% medium-term notes due May 2051	$400
	May 2021	2.82% medium-term notes due May 2031	$400

1 Notes mature in two years and carry an interest rate set to equal SOFR plus a margin of 40 basis points.

LONG-TERM DEBT REPAYMENTS

During the six months ended June 30, 2021, we completed the following long-term debt repayments totaling $808 million and US$880 million:

Company	Repayment Date		Principal Amount
(millions of Canadian dollars unless otherwise stated)			
Enbridge Inc.			
	February 2021	4.26% medium-term notes	$200
	March 2021	3.16% medium-term notes	$400
Enbridge Energy Partners, L.P.			
	June 2021	4.20% senior notes	US$600
Enbridge Gas Inc.			
	May 2021	2.76% medium-term notes	$200
Enbridge Pipelines (Southern Lights) L.L.C.			
	June 2021	3.98% senior notes	US$30
Enbridge Southern Lights LP			
	June 2021	4.01% senior notes	$8
Spectra Energy Partners, LP			
	March 2021	4.60% senior notes	US$250

Strong internal cash flow, 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.

On June 1, 2021, Moody's upgraded the credit ratings of Enbridge Inc. including our senior unsecured and issuer ratings to Baa1 from Baa2. Moody's also upgraded the credit ratings of our subsidiaries: EEP, EELP, SEP and Texas Eastern. The outlooks of all five entities are stable.

There are no material restrictions on our cash. Total restricted cash of $85 million, as reported on the Consolidated Statements of Financial Position, primarily includes 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, we had a negative working capital position as at June 30, 2021. The major contributing factor to the negative working capital position was the ongoing funding of our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due.

SOURCES AND USES OF CASH

	Six months ended June 30,	
	2021	2020
(millions of Canadian dollars)		
Operating activities	**4,791**	5,225
Investing activities	**(3,339)**	(2,266)
Financing activities	**(1,463)**	(3,124)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	**(20)**	(14)
Net decrease in cash and cash equivalents and restricted cash	**(31)**	(179)

Significant sources and uses of cash for the six months ended June 30, 2021 and 2020 are summarized below:

Operating Activities

The decrease in cash provided by operating activities was primarily attributable to changes in operating assets and liabilities. Our operating assets and liabilities fluctuate in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally.

Investing Activities

- The increase in cash used in investing activities was attributable to higher capital expenditures during the six months ended June 30, 2021 compared to the same period in 2020. We are continuing with the execution of our growth capital program which is further described in *Growth Projects - Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements. In addition, there were higher proceeds received from dispositions in the second quarter of 2020, as compared to proceeds received from disposition of 49% of our interest in EMF to CPP Investments in the first quarter of 2021.
- The above factors were offset by the absence of contributions to the Gray Oak Holdings LLC equity investment in the first half of 2021 compared to the same period in 2020, due to the fact that Gray Oak Pipeline was placed into service in March 2020.

Financing Activities

- The decrease in cash used in financing activities was primarily attributable to a decrease in repayments of long-term debt and an increase in short-term borrowings.
- The factor above was partially offset by a decrease in issuances of long-term debt, a decrease in commercial paper and credit facility draws, and the redemption of Westcoast Energy Inc.'s preferred shares in the first quarter of 2021.
- Our common share dividend payments increased period-over-period primarily due to the increase in our common share dividend rate.

SUMMARIZED FINANCIAL INFORMATION

On January 22, 2019, Enbridge entered into supplemental indentures with its wholly-owned subsidiaries, SEP and EEP (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. 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 senior notes.

Consenting SEP notes and EEP notes under Guarantee

SEP Notes[1]	EEP Notes[2]
4.750% Senior Notes due 2024	5.875% Notes due 2025
3.500% Senior Notes due 2025	5.950% Notes due 2033
3.375% Senior Notes due 2026	6.300% Notes due 2034
5.950% Senior Notes due 2043	7.500% Notes due 2038
4.500% Senior Notes due 2045	5.500% Notes due 2040
	7.375% Notes due 2045

1 As at June 30, 2021, the aggregate outstanding principal amount of SEP notes was approximately US$3.2 billion.
2 As at June 30, 2021, the aggregate outstanding principal amount of EEP notes was approximately US$2.4 billion.

Enbridge Notes under Guarantees

USD Denominated[1]	CAD Denominated[2]
Floating Rate Senior Notes due 2022	4.850% Senior Notes due 2022
Floating Rate Senior Notes due 2023	3.190% Senior Notes due 2022
2.900% Senior Notes due 2022	3.940% Senior Notes due 2023
4.000% Senior Notes due 2023	3.940% Senior Notes due 2023
3.500% Senior Notes due 2024	3.950% Senior Notes due 2024
2.500% Senior Notes due 2025	2.440% Senior Notes due 2025
4.250% Senior Notes due 2026	3.200% Senior Notes due 2027
3.700% Senior Notes due 2027	6.100% Senior Notes due 2028
3.125% Senior Notes due 2029	2.990% Senior Notes due 2029
2.500% Sustainability-Linked Senior Notes due 2033	7.220% Senior Notes due 2030
4.500% Senior Notes due 2044	7.200% Senior Notes due 2032
5.500% Senior Notes due 2046	5.570% Senior Notes due 2035
4.000% Senior Notes due 2049	5.750% Senior Notes due 2039
3.400% Senior Notes due 2051	5.120% Senior Notes due 2040
	4.240% Senior Notes due 2042
	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.560% Senior Notes due 2064

1 As at June 30, 2021, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US$9.5 billion.
2 As at June 30, 2021, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately $7.7 billion.

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

Summarized Combined Statement of Earnings

	Six months ended June 30, 2021
(millions of Canadian dollars)	
Operating income	**(30)**
Earnings	**1,999**
Earnings attributable to common shareholders	**1,817**

Summarized Combined Statements of Financial Position

(millions of Canadian dollars)	**June 30, 2021**	December 31, 2020
Accounts receivable from affiliates	**2,626**	2,108
Short-term loans receivable from affiliates	**4,840**	4,926
Other current assets	**528**	375
Long-term loans receivable from affiliates	**45,281**	43,217
Other long-term assets	**3,971**	4,237
Accounts payable to affiliates	**1,607**	1,267
Short-term loans payable to affiliates	**4,584**	4,117
Other current liabilities	**4,435**	5,628
Long-term loans payable to affiliates	**35,854**	32,035
Other long-term liabilities	**38,989**	41,353

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 of 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.

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Michigan Line 5 Dual Pipelines - Straits of Mackinac Easement
In 2019, the Michigan Attorney General filed a complaint in the Michigan Ingham County Circuit Court (the Court) that requests the Court to declare the easement granted in 1953 that we have for the operation of Line 5 in the Straits of Mackinac (the Straits) to be invalid and to prohibit continued operation of Line 5 in the Straits “as soon as possible after a reasonable notice period to allow orderly adjustments by affected parties”. Ruling on the motions is currently being held in abeyance by the Court pending further developments in the Federal Court cases described below.

On November 13, 2020, the Governor of Michigan and the Director of the Michigan Department of Natural Resources notified us that the State of Michigan (the State) was revoking and terminating the easement granted in 1953 that allows Line 5 to operate across the Straits. The notice demands that the portion of Line 5 that crosses the Straits must be shut down by May 2021. On November 24, 2020, we filed in the US District Court for the Western District of Michigan a Notice of Removal, which removed the State’s November Complaint to Federal Court and a Complaint for Declaratory and Injunctive Relief that requests the US District Court to enjoin the Governor from taking any action to prevent or impede the operation of Line 5. On February 18, 2021, the Judge ruled that the motion to remand back to State Court will be briefed and decided first. Parties were also ordered to collaborate and identify a facilitative mediator. Accordingly, retired US District Court Judge Gerald Rosen was chosen to act as mediator. The parties have had multiple mediation sessions with the mediator.

On January 12, 2021, we responded to the Governor’s Notice of Revocation and Termination of Easement. On February 11, 2021, we sent a further letter to the Department of Natural Resources regarding our rights under the easement and renewing the request to meet and have technical discussions to better understand the State’s concerns. On May 11, 2021, the Governor sent a letter to us stating that if we continued to operate in the Straits past May 12, 2021, the State would consider us as intentionally trespassing and therefore we will be unjustly enriched entitling the State to all profits derived from wrongful use of the State's property. On May 21, 2021, we responded to the letter refuting the State's claims that the pipelines are in trespass. We will vigorously defend our ability to operate Line 5 under the 1953 easement in pending Court actions.

In March 2021, we completed the engineering and design phase of the Great Lakes Tunnel Project and we have begun the process of hiring a contractor to construct the tunnel. We are actively pursuing state and federal regulatory permits from the US Army Corps of Engineers (Army Corps), the Michigan Department of Environment, Great Lakes & Energy (EGLE) and the Michigan Public Service Commission. The EGLE permits were granted in the first quarter of 2021; one of the EGLE permits has been challenged by the Bay Mills Indian Community.

On June 23, 2021, the Army Corps announced they would proceed with an EIS for the Great Lakes Tunnel Project to replace Line 5 at the Straits. On June 23 2021, we issued a statement stating that construction on this project would be delayed due to the EIS.

Dakota Access Pipeline
We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of 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) contesting the lawfulness of the Army Corps easement for DAPL, including 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.

On June 14, 2017, the District Court found the Army Corps' environmental review to be deficient and ordered the Army Corps to conduct further study concerning spill risks from DAPL. In August 2018, the Army Corps completed on remand the further environmental review ordered by the District Court and reaffirmed the issuance of the easement for DAPL. All four plaintiff Tribes subsequently amended their complaints to include claims challenging the adequacy of the Army Corps' August 2018 remand decision.

On March 25, 2020, in response to amended complaints from the Tribes, the District Court found the Army Corps' environmental review on remand was deficient and ordered the Army Corps to prepare an EIS to address unresolved controversy pertaining to potential spill impacts resulting from DAPL. On July 6, 2020, the District Court issued an order vacating the Army Corps' easement for DAPL and ordering that the pipeline be shut down by August 5, 2020. Dakota Access, LLC and the Army Corps appealed the decision and filed a motion for a stay pending appeal with the US Court of Appeals for the District of Columbia Circuit. On August 5, 2020, the US Court of Appeals stayed the District Court's July 6 order to shut down and empty the pipeline, but did not stay the District Court's March 25 order requiring the Army Corps to prepare an EIS or the District Court's July 6 order vacating the DAPL easement.

On January 26, 2021, the US Court of Appeals affirmed the District Court's decision, holding that the Army Corps is required to prepare an EIS and that the Army Corps' easement for DAPL is vacated. The US Court of Appeals also determined that, absent considering the closure of DAPL in the context of an injunction proceeding, the District Court could not order DAPL's operations to cease. While not an issue before the US Court of Appeals, the US Court of Appeals also recognized that the Army Corps could consider whether to allow DAPL to continue to operate in the absence of an easement.

On May 21, 2021, the District Court dismissed the plaintiff Tribes' request for an injunction enjoining DAPL from operating until the Army Corps has completed its EIS. The right of the plaintiff Tribes to appeal the denial of the injunction request expired on July 20, 2021. The Army Corps earlier indicated that it did not intend, at that time, to exercise its authority to bar DAPL's continued operation, notwithstanding the absence of an easement and that it anticipates completing its EIS by March 2022.

On July 22, 2021, the Army Corps filed a notice with the District Court advising that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a notice asserting violations of federal safety regulations resulting from the operation of DAPL. The Army Corps stated that it would consider PHMSA's notice as part of its ongoing consideration of whether and how the Army Corps will enforce its rights on property crossed by the pipeline and in the context of the ongoing EIS. The Army Corps further reported that it has received, but had not made any decisions on, requests from the Tribes to extend certain timelines, including an extension of the EIS completion date to September 2022.

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

CAPITAL EXPENDITURE COMMITMENTS
We have signed contracts for the purchase of services, pipe and other materials totaling approximately $2.5 billion which are expected to be paid over the next five years.

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

CHANGES IN ACCOUNTING POLICIES

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