



**ENBRIDGE INC.**

**MANAGEMENT'S DISCUSSION AND ANALYSIS**

**December 31, 2021**

## **INTRODUCTION**

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information" and "Non-GAAP and Other Financial Measures", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

This section of our Annual Report on Form 10-K discusses 2021 and 2020 items and year-over-year comparisons between 2021 and 2020. For discussion of 2019 items and year-over-year comparisons between 2020 and 2019, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2020.

## **RECENT DEVELOPMENTS**

### **ACQUISITION OF MODA MIDSTREAM OPERATING, LLC**

On October 12, 2021, we acquired Moda Midstream Operating, LLC (Moda) for \$3.7 billion (US\$3.0 billion) of cash plus potential contingent payments dependent on performance of the assets (the Acquisition). Moda owns and operates a vertically-integrated crude export system of pipeline and storage assets on the US Gulf Coast, including the EIEC located near Corpus Christi, Texas. EIEC, North America's largest crude export terminal, controls 15.6 million barrels of storage and 1.6 million barrels per day (mmbpd) of export capacity and volumes are underpinned by 925- thousand barrels per day (kbpd) of long-term take-or-pay vessel loading contracts and 15.3 million barrels of long-term storage contracts. The Acquisition aligns with and advances our US Gulf Coast export strategy and connectivity to low-cost and long-lived reserves in the Permian and Eagle Ford basins.

### **NORMAL COURSE ISSUER BID**

On December 31, 2021, we announced that the Toronto Stock Exchange (TSX) had approved our normal course issuer bid (NCIB) to purchase, for cancellation, up to 31,062,331 of the outstanding common shares of Enbridge to an aggregate amount of up to \$1.5 billion, subject to certain restrictions on the number of common shares that may be purchased on a single day.

Purchases under the NCIB may be made through the facilities of the TSX, the New York Stock Exchange (NYSE) and other designated exchanges and alternative trading systems, commencing on January 5, 2022 and continuing until January 4, 2023, when the bid expires, or such earlier date on which Enbridge has either acquired the maximum number of common shares allowable under the NCIB or otherwise decide not to make any further repurchases under the NCIB. The maximum number of common shares that Enbridge may repurchase for cancellation represents approximately 1.53% of the 2,026,085,179 common shares issued and outstanding as at December 22, 2021.

## **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. On November 26, 2021, the CER denied the application on the basis that, among other things, contracting as proposed would result in a significant change to access the Canadian Mainline and potentially inequitable outcomes to some shippers and non-shippers without a compelling justification.

We are currently exploring with customers and other stakeholders alternatives that may include: a modified and extended Competitive toll Settlement (CTS), a new incentive rate-making agreement or a cost-of-service rate-making structure. Any negotiated settlement would require CER approval before implementation.

In accordance with the terms of the 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) filed a rate case on July 30, 2021. On August 31, 2021 the Federal Energy Regulatory Commission (FERC) issued an order rejecting the July 30, 2021 filing in its entirety noting the proposed US federal income tax rate in the filing was not known and measurable ("August 2021 Order"). Additionally, the August 31, 2021 order directed Texas Eastern to show cause that its reservation charge crediting process is in accordance with FERC policy.

In response to the August 2021 Order, on September 30, 2021 Texas Eastern responded to the show cause directive and filed a new rate case using the current US federal income tax rate. On October 29, 2021, the FERC issued an order accepting and suspending tariff records, subject to refund, conditions, and establishing hearing procedures for the new rate case filed on September 30, 2021.

Texas Eastern also filed for rehearing of the August 2021 Order. On January 20, 2022 the FERC issued an "Order Addressing Arguments Raised On Rehearing And Setting Aside Prior Order, In Part" ("January 2022 Order"). The January 2022 Order set aside the August 2021 Order, and accepted and suspended Texas Eastern's proposed rates from its initial rate case filing to be effective upon motion on February 1, 2022, subject to refund, conditions, and the outcome of hearing proceedings. In addition, the January 2022 Order directed Texas Eastern to remove its proposed income tax adjustment and include the actual tax rate in the computation of its rates when it files to motion the suspended rates into effect.

Finally, the FERC left to the discretion of the Chief Administrative Law Judge whether to consolidate the two rate case proceedings.

### **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, approved by the FERC on September 10, 2021 and was effective on November 1, 2021.

### **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 17, 2021, approved by the FERC on April 30, 2021 and was effective on June 1, 2021. In December 2021, the CER approved interim rates for the Canadian portion of Maritimes & Northeast Pipeline effective January 1, 2022, which were based on the negotiated 2022 rates in the 2022-2023 settlement agreement and unanimously supported by shippers. A decision from the CER on the 2022-2023 settlement agreement is expected in the first quarter of 2022.

### **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 was effective on September 1, 2021.

### **British Columbia (BC) Pipeline**

The settlement agreement for our BC Pipeline system expired in December 2021. The CER has approved 2022 interim tolls for BC Pipeline and settlement agreement negotiations are ongoing, with an expected agreement to be reached in the first half of 2022.

## **GAS DISTRIBUTION AND STORAGE RATE APPLICATIONS**

### **2021 Rate Application**

Enbridge Gas Inc.'s (Enbridge Gas) rate applications are filed in two phases. As part of an Ontario Energy Board (OEB) Decision and Order issued in November 2020, Phase 1 of the application for 2021 rates (the 2021 Application), exclusive of 2021 capital investment funding requested through the incremental capital module (ICM) mechanism, was approved on an interim basis effective January 1, 2021. Through a subsequent OEB Rate Order issued in June 2021, Phase 2 of the 2021 Application, inclusive of funding for \$124 million of requested 2021 ICM amounts, was approved effective July 1, 2021, and interim rates in effect for 2021 were made final. The 2021 Application, which represented the third year of a five-year term, was filed in accordance with the parameters of the Enbridge Gas OEB approved Price Cap Incentive Regulation (IR) rate setting mechanism.

### **2022 Rate Application**

In June 2021, Enbridge Gas filed Phase 1 of the application with the OEB for the setting of rates for 2022 (the 2022 Application). The 2022 Application was filed in accordance with the parameters of the Enbridge Gas OEB approved Price Cap IR rate setting mechanism which represents the fourth year of a five-year term. In October 2021, the OEB approved a Phase 1 Settlement Proposal and Interim Rate Order effective January 1, 2022. Phase 2 of the 2022 Application addressing ICM funding requirements was filed in October 2021, with a decision from the OEB expected in the second quarter of 2022.

## **FINANCING UPDATE**

We completed long-term debt issuances totaling US\$3.9 billion and \$3.2 billion during the year ended December 31, 2021, including an inaugural US\$1.0 billion 12-year sustainability-linked senior notes issuance in June 2021 and an inaugural \$1.1 billion Canadian 12-year sustainability-linked medium-term notes issuance in September 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.

Our 2021 financing activities, in combination with the asset monetization activities noted below, provide significant liquidity that we expect will enable us to fund our current portfolio of capital projects without requiring access to the capital markets for the next 12 months should market access be restricted or pricing is unattractive. Refer to *Liquidity and Capital Resources*.

On January 19, 2022, we closed a \$750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2032. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

On February 10, 2022 we renewed our three year \$1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

### **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.

### **ENERGY TRANSITION**

Given the priority we are placing on low carbon investments and energy transition, we have established a dedicated New Energy Technologies team. This team will extend the capabilities we have built over the last 20 years of renewable investments and will establish priorities and co-ordinate strategy across our business units. The team will also develop new partnerships to enable access to new technology, complementary assets and skills.

During 2021, the Alberta Solar One and Heidlersburg solar self-power projects were placed into service. We also started the construction process on 10 additional solar self-power projects in Wisconsin, Illinois, Pennsylvania, Kentucky, Ohio and Minnesota, together capable of generating more than 97 megawatts (MW) MW of emissions-free electricity. These projects will provide clean power to our liquids and natural gas pipeline right-of-way and support scope 1 and 2 emission targets.

### **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 and are under construction.

#### **Noverco Inc.**

On December 30, 2021, we sold our 38.9% non-operating minority ownership interest in Noverco Inc. (Noverco) to Trentcap L.P. for \$1.1 billion in cash.

## FORWARD-LOOKING INFORMATION

*Forward-looking information, or forward-looking statements, have been included in this management's discussion and analysis (MD&A) to provide information about us and our subsidiaries and affiliates, including management's assessment of our and our subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "believe", "estimate", "expect", "forecast", "intend", "likely", "plan", "project", "target" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: our corporate vision and strategy, including strategic priorities and enablers; the COVID-19 pandemic and the duration and impact thereof; energy intensity and emissions reduction targets and related Environment, Social and Governance (ESG) matters; diversity and inclusion goals; expected supply of, demand for, and prices of crude oil, natural gas, natural gas liquids (NGLs), liquified natural gas 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 and for maintenance; 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; United States 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, NGLs 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, NGLs and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation, interest rates and 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, 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 Dakota Access Pipeline (DAPL) and the 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.

### Non-GAAP and Other Financial Measures

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

The non-GAAP and other financial measures described above are not measures that have a standardized meaning prescribed by generally accepted accounting principles in the United States of America (U.S. GAAP) and are not U.S. GAAP measures. Therefore, these measures may not be comparable with similar measures presented by other issuers. A reconciliation of historical non-GAAP and other financial measures to the most directly comparable GAAP measures is set out in this MD&A and is available on our website. Additional information on non-GAAP and other financial measures may be found on our website, [www.sedar.com](http://www.sedar.com).

## RESULTS OF OPERATIONS

	Year ended December 31,		
	2021	2020	2019
<i>(millions of Canadian dollars, except per share amounts)</i>			
<b>Segment earnings before interest, income taxes and depreciation and amortization<sup>1</sup></b>			
Liquids Pipelines	7,897	7,683	7,681
Gas Transmission and Midstream	3,671	1,087	3,371
Gas Distribution and Storage	2,117	1,748	1,747
Renewable Power Generation	508	523	111
Energy Services	(313)	(236)	250
Eliminations and Other	356	(113)	429
<b>Earnings before interest, income taxes and depreciation and amortization<sup>1</sup></b>	<b>14,236</b>	10,692	13,589
Depreciation and amortization	(3,852)	(3,712)	(3,391)
Interest expense	(2,655)	(2,790)	(2,663)
Income tax expense	(1,415)	(774)	(1,708)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(125)	(53)	(122)
Preference share dividends	(373)	(380)	(383)
<b>Earnings attributable to common shareholders</b>	<b>5,816</b>	2,983	5,322
Earnings per common share	2.87	1.48	2.64
Diluted earnings per common share	2.87	1.48	2.63

<sup>1</sup> Non-GAAP financial measures.

## EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

### Year ended December 31, 2021 compared with year ended December 31, 2020

Earnings Attributable to Common Shareholders increased by \$2.2 billion due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized net gain of \$53 million (\$40 million after-tax) in 2021, compared with an unrealized net loss of \$122 million (\$92 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;
- an impairment loss of \$111 million (\$83 million after-tax) in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development, compared to a combined impairment loss of \$615 million (\$452 million after-tax) in 2020 to our investments in Southeast Supply Header (SESH) and Steckman Ridge, LP (Steckman);
- a gain of \$303 million (\$298 million after-tax) resulting from the sale of our investment in Noverco;
- employee severance, transition and transformation costs of \$147 million (\$112 million after-tax) in 2021, compared to \$339 million (\$256 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) and a \$324 million loss (\$244 million after-tax) resulting from our share of asset and goodwill impairments recognized by DCP Midstream, both recognized in 2020; and
- the absence in 2021 of a \$159 million loss (\$119 million after-tax) recorded in 2020 to reflect 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; partially offset by
- a non-cash, unrealized derivative fair value net gain of \$197 million (\$150 million after-tax) in 2021, compared with a net gain of \$856 million (\$646 million after-tax) 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 non-cash, unrealized derivative fair value gains and losses discussed above generally arise as a result of a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on financial derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining \$657 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 enabled by incremental Line 3 capacity placed into service in the fourth quarter of 2021 and a higher Mainline International Joint Tariff (IJT) Benchmark Toll, partially offset by the recognition of a provision against the interim Mainline IJT for barrels shipped between July 1, 2021 and December 31, 2021;
- increased earnings from our Gas Distribution and Storage segment due to increased rates and customer base;
- higher equity earnings from our Aux Sable and DCP Midstream joint ventures in our Gas Transmission and Midstream; and
- lower interest expense for the first nine months of 2021 due to favourable interest rates on short-term borrowings, and the impact of a weaker US dollar currency that positively impacted the translation of interest payments on US dollar denominated debt.

The 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;
- 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 revenue in 2020 from a rate settlement on Texas Eastern, partially offset by increased revenue due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- higher depreciation expense on new assets placed into service throughout 2021, including the US L3R Program, placed into service early in the fourth quarter and the EIEC, acquired in mid-October.

## **REVENUES**

We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales.

Transportation and other services revenues of \$16.2 billion, \$16.2 billion and \$16.6 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator and, in most cost-of-service based arrangements, are reflective of our cost to provide the service plus a regulator-approved rate of return.

Gas distribution sales revenues of \$4.0 billion, \$3.7 billion and \$4.2 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales revenues of \$26.9 billion, \$19.3 billion and \$29.3 billion for the years ended December 31, 2021, 2020 and 2019, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGLs) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

Our revenues also include changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but we believe over the long-term, the economic hedging program supports reliable cash flows.

## BUSINESS SEGMENTS

### LIQUIDS PIPELINES

	2021	2020	2019
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization <sup>1</sup>	7,897	7,683	7,681

<sup>1</sup> Non-GAAP financial measure.

#### Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was negatively impacted by \$335 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized gain of \$120 million in 2021 compared with an unrealized gain of \$545 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 factor above was partially offset by the following:

- a property tax settlement receipt of \$57 million in 2021 related to the resolution of Minnesota property tax appeals for the tax years 2012 through 2018; and
- the absence in 2021 of \$30 million of asset impairment losses recognized in 2020.

After taking into consideration the factors above, the remaining \$549 million increase is primarily explained by the following factors:

- higher Mainline system ex-Gretna average throughput of 2.8 million barrels per day (mmbpd) in 2021 as compared to 2.6 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;
- incremental L3R capacity that came into service October 2021 further supporting demand growth and the implementation of full L3R surcharge of US\$0.93 per barrel beginning October 2021 compared to the Canadian L3R program US\$0.20 per barrel;
- a higher average IJT Benchmark Toll on our Mainline System of US\$4.27 in 2021, compared with US\$4.24 in 2020;
- a higher foreign exchange hedge rate used to lock-in US dollar denominated Canadian Mainline revenue; and
- higher equity income from our investment in the Seaway Crude Pipeline System driven by increased volumes.

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

- the recognition of a provision in the fourth quarter against the interim Mainline IJT for barrels shipped between July 1, 2021 and December 31, 2021; and
- the net unfavorable effect of translating US dollar EBITDA to Canadian dollars at a lower average exchange rate in 2021 versus 2020.

## GAS TRANSMISSION AND MIDSTREAM

	2021	2020	2019
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization <sup>1</sup>	3,671	1,087	3,371

<sup>1</sup> Non-GAAP financial measure.

### Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by \$2.6 billion due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- an impairment loss of \$111 million in 2021 to our investment in the PennEast pipeline project after a decision by project partners to cease development, compared to a combined impairment loss of \$615 million in 2020 to our investments in SESH and Steckman;
- the absence in 2021 of a \$1.7 billion non-cash impairment to the carrying value of our investment in DCP Midstream and a \$324 million loss resulting from our share of asset and goodwill impairments recognized by DCP Midstream, both recognized in 2020;
- the absence in 2021 of a \$159 million loss recorded in 2020 to reflect the Texas Eastern rate case settlement that re-established the EDIT regulated liability that was previously eliminated in December 2018; partially offset by
- a negative impact in equity earnings of \$44 million in 2021, compared with a positive impact of \$22 million in 2020 relating to changes in the mark-to-market value of derivative financial instruments within our equity method investee, DCP Midstream.

After taking into consideration the factors above, we saw a \$45 million decrease to EBITDA that is primarily explained by the following 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 revenue in 2020 that related to the settlement of interim rates collected from shippers on Texas Eastern, retroactive to June 1, 2019.

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

- higher commodity prices benefiting equity earnings from our Aux Sable and DCP Midstream joint ventures;
- increased revenue due to the absence of pressure restrictions that existed on the Texas Eastern system in 2020; and
- a full year of contributions from the Atlantic Bridge Phase III project after it commenced service in January of 2021.

## GAS DISTRIBUTION AND STORAGE

	2021	2020	2019
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization <sup>1</sup>	2,117	1,748	1,747

<sup>1</sup> Non-GAAP financial measure.

### Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by \$338 million due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- a gain of \$303 million resulting from the sale of our investment in Noverco; and
- a non-cash, unrealized gain of \$14 million in 2021, compared with a loss of \$10 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.

After taking into consideration the positive factors above, the remaining \$31 million increase is primarily explained by the following significant business factors:

- higher distribution charges resulting from increases in rates and customer base; and
- higher storage revenue, mainly relating to storage optimization activities.

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

- higher operating and administrative costs largely related to operational, pipeline integrity and safety costs; and
- when compared with the normal weather forecast embedded in rates, weather was warmer in both 2021 and 2020, negatively impacting EBITDA in both years. Warmer than normal weather in 2021 negatively impacted 2021 EBITDA by approximately \$55 million, while the warmer than normal weather in 2020 negatively impacted 2020 EBITDA by approximately \$33 million.

## RENEWABLE POWER GENERATION

	2021	2020	2019
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization <sup>1</sup>	508	523	111

<sup>1</sup> Non-GAAP financial measure.

### Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was negatively impacted by \$15 million primarily explained by the following significant business factors:

- weaker wind resources at Canadian and United States wind facilities and the effects from the Texas winter storm in February 2021; and
- the absence in 2021 of reimbursements received in 2020 at certain Canadian wind facilities resulting from a change in operator; partially offset by
- the sale of a 49% interest of an entity that holds our 50% interest in EMF.

## ENERGY SERVICES

	2021	2020	2019
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization <sup>1</sup>	(313)	(236)	250

<sup>1</sup> Non-GAAP financial measure.

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.

### Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by \$164 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized net gain of \$53 million in 2021, compared with a loss of \$122 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 positive factors above, the remaining \$241 million decrease is primarily explained by the following significant business 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

	2021	2020	2019
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization <sup>1</sup>	356	(113)	429

<sup>1</sup> Non-GAAP financial measure.

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

### Year ended December 31, 2021 compared with year ended December 31, 2020

EBITDA was positively impacted by \$24 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- employee severance, transition and transformation costs of \$87 million in 2021 compared with \$279 million 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 loss of \$74 million in 2020 relating to the recognition of a corporate guarantee obligation; and
- the absence in 2021 of a loss of \$43 million in 2020 relating to the write-down of certain investments in emerging energy and other technologies; partially offset by
- a non-cash, unrealized gain of \$55 million in 2021 compared with a gain of \$318 million in 2020 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk.

After taking into consideration the factors above, the remaining \$445 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.

## GROWTH PROJECTS – COMMERCIALY SECURED PROJECTS

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

	Enbridge's Ownership Interest	Estimated Capital Cost <sup>1</sup>	Expenditures to Date <sup>2</sup>	Status <sup>2</sup>	Expected In-Service Date
<i>(Canadian dollars, unless stated otherwise)</i>					
<b>LIQUIDS PIPELINES</b>					
1. US Line 3 Replacement Program	100 %	US\$4.0 billion	US\$4.1 billion	Complete	In-service
2. Southern Access Expansion	100 %	US\$0.5 billion	US\$0.5 billion	Complete	In-service
3. Other - US	100 %	US\$0.1 billion	US\$0.1 billion	Complete	In-service
<b>GAS TRANSMISSION AND MIDSTREAM</b>					
4. T-South Reliability & Expansion Program	100 %	\$1.0 billion	\$0.9 billion	Complete	In-service
5. Spruce Ridge Project	100 %	\$0.4 billion	\$0.4 billion	Complete	In-service
6. Texas Eastern Modernization	100 %	US\$0.4 billion	No significant expenditures to date	Pre-construction	2024 - 2026
7. Appalachia to Market II	100 %	US\$0.1 billion	No significant expenditures to date	Pre-construction	2025
8. Other - US <sup>3</sup>	Various	US\$0.6 billion	US\$0.4 billion	Various stages	2021 - 2023
<b>GAS DISTRIBUTION AND STORAGE</b>					
9. System Enhancement Projects <sup>4</sup>	100 %	\$0.4 billion	\$0.1 billion	Various stages	2021 - 2023
10. Storage Enhancements	100 %	\$0.1 billion	No significant expenditures to date	Under construction	2H - 2022
11. Natural Gas Expansion Program <sup>5</sup>	100 %	\$0.1 billion	No significant expenditures to date	Pre-construction	2022 - 2027
<b>RENEWABLE POWER GENERATION</b>					
12. East-West Tie Line	25.0 %	\$0.2 billion	\$0.2 billion	Under construction	1H - 2022
13. Solar Self-Power Projects <sup>6</sup>	100 %	US\$0.2 billion	No significant expenditures to date	Pre-construction	2022 - 2023
14. Saint-Nazaire France Offshore Wind Project <sup>7</sup>	25.5 %	\$0.9 billion (€0.6 billion)	\$0.5 billion (€0.3 billion)	Under construction	2H - 2022
15. Provence Grand Large Floating Offshore Wind Project <sup>8</sup>	25.0 %	\$0.1 billion (€0.1 billion)	No significant expenditures to date	Pre-construction	2023
16. Fécamp Offshore Wind Project <sup>9</sup>	17.9 %	\$0.7 billion (€0.5 billion)	\$0.3 billion (€0.2 billion)	Under construction	2023
17. Calvados Offshore Wind Project <sup>9</sup>	21.7 %	\$0.9 billion (€0.6 billion)	\$0.1 billion (€0.1 billion)	Pre-construction	2024

<sup>1</sup> 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.

<sup>2</sup> Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2021.

<sup>3</sup> Includes the US\$0.1 billion Texas Eastern Middlesex Extension placed into service in September of 2021 and the US\$0.1 billion Cameron Extension Project placed into service in November of 2021.

- 4 Includes the \$0.1 billion London Line Replacement Project placed into service in December of 2021. Total estimated capital cost consists of site restoration work expected to be completed in 2022.
- 5 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.
- 6 Self-Power Projects consists of solar self-power projects along our liquids and gas transmission systems. All 10 projects will be located at existing pump and/or compressor stations.
- 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 \$0.15 billion, with the remainder of the project financed through non-recourse project level debt.
- 8 Reflects the sale of 50% of an entity that holds our 50% interest in Provence Grand Large to CPP Investments. Our equity contribution is \$0.05 billion, with the remainder of the project financed through non-recourse project level debt for each project.
- 9 Each project 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.

Risks related to the development and completion of growth projects are described under Part I. *Item 1A. Risk Factors.*

## LIQUIDS PIPELINES

The following commercially secured growth projects were placed into service in 2021:

- **United States Line 3 Replacement Program** – replacement of the existing Line 3 crude oil pipeline between Neche, North Dakota and Superior, Wisconsin is now complete and in-service. The US L3R Program supports the safety and operational reliability of the Mainline System, enhances system flexibility and allows us to optimize throughput on the mainline. The US L3R Program restored the original capacity of 760 kbpd and brought the total Mainline System operating capacity to approximately 3.1 mmbpd.
- **Southern Access Expansion** – expansion of our existing Southern Access crude oil pipeline from 996 kbpd to approximately 1,200 kbpd.

## GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth projects were placed into service in 2021:

- **Atlantic Bridge Phase III** – an expansion of the Algonquin natural gas transmission systems which transports 133 million cubic feet per day (mmcf/d) of natural gas to the New England region. The third and final phase of Atlantic Bridge fully commenced service in January 2021 with the Weymouth compressor station being brought online.
- **T-South Reliability & Expansion Program** – a natural gas pipeline expansion of Westcoast's BC Pipeline in southern BC that provides improved compressor reliability and additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the US/Canada border.
- **Spruce Ridge Project** – a natural gas pipeline expansion of Westcoast's BC Pipeline in northern BC. The project provides additional capacity of up to 402 mmcf/d.

The following commercially secured growth projects are currently in pre-construction stages:

- **Texas Eastern Modernization Phase II** – this program is the modernization of compression facilities in Pennsylvania and New Jersey to increase safety and reliability and reduce associated greenhouse gas emissions at multiple sites on our Texas Eastern system. The program will be completed in stages over a period of years beginning in 2024.

- **Appalachia to Market II** - the expansion is designed to deliver 55 MDth per day on the Texas Eastern pipeline from the Appalachia supply basin in Southwest Pennsylvania to existing local distribution company customers in New Jersey beginning in late 2025. The project is a brown-field expansion and upgrade of existing Texas Eastern facilities in Pennsylvania.

## **GAS DISTRIBUTION AND STORAGE**

The following commercially secured growth project was placed into service in 2021:

- **System Enhancement Projects** – The London Line Replacement Project replaced two existing pipelines known collectively as the London Line and included the construction of approximately 90.5-kilometers of natural gas pipeline and ancillary facilities in southern Ontario.

The following commercially secured growth projects are currently in various stages of construction:

- **System Enhancement Project** – The Lake Shore Kipling Oshawa Loop (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 KOL along Lake Shore Boulevard in the City of Toronto. The St. Laurent Ottawa North Replacement Project is a replacement of approximately 16-kilometers of natural gas pipeline in the City of Ottawa. The first two phases of this project have already been completed. Phases 3 and 4 represent approximately 11.4-kilometers of pipeline.
- **Storage Enhancements** – Storage Enhancements are part of a larger delta pressuring project to increase deliverability and storage capacity at Enbridge Gas' storage facilities. The additional deliverability and storage capacity will be sold as part of Enbridge Gas' unregulated storage portfolio.
- **Natural Gas 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. Under Phase 2 of the Program, we will be provided up to \$214 million in funding assistance to deliver 25 community expansion and two economic development projects throughout Ontario.

## **RENEWABLE POWER GENERATION**

The following commercially secured growth projects are currently in various stages of construction:

- **East-West Tie Line** – a transmission project that will parallel an existing double-circuit, 230 kilovolt transmission line that connects the Wawa Transformer Station to the Lakehead Transformer Station near Thunder Bay, Ontario, including a connection midway in Marathon, Ontario.
- **Solar Self-Power Projects** – 10 solar self-power projects under development in Wisconsin, Illinois, Pennsylvania, Kentucky, Ohio and Minnesota, with a combined estimate of 97 MW of emissions-free generating capacity. These projects will provide clean power directly to our liquids and natural gas pipeline rights-of-way.
- **Saint-Nazaire France Offshore Wind Project** – a wind project located off the west coast of France that is expected to generate approximately 480-MW. Project revenues are backed by a 20-year fixed price power purchase agreement (PPA) with added power production protection.
- **Provence Grand Large Floating Offshore Wind Project** – a floating offshore wind facility off the southern coast of France that secured funding in 2021 and continues to prepare onshore construction and is expected to generate approximately 24-MW. Project revenues are underpinned by a 20-year fixed price PPA.

- **Fécamp Offshore Wind Project** – an offshore wind project located off the northwest coast of France and is expected to generate approximately 500-MW. Project revenues are underpinned by a 20-year fixed price PPA.
- **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.

## OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

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

### LIQUIDS PIPELINES

- **Sea Port Oil Terminal Project** – the Sea Port Oil Terminal (SPOT) project consists of onshore and offshore facilities, including a fixed platform located approximately 30 miles off the coast of Brazoria County, Texas. SPOT is designed to load very large crude carriers at rates of approximately 85,000 barrels per hour, or up to approximately 2 million bpd. Along with Enterprise Products Partners, L.P., we announced our intent to jointly develop and market SPOT, and we will work to finalize an equity participation agreement. The agreement will allow us to purchase an ownership interest in SPOT, subject to SPOT receiving a deep-water port license.
- **Enbridge Houston Oil Terminal** – the terminal is expected to have an ultimate capability of up to 15 million barrels of storage, access to crude oil from all major North American production basins and will be fully integrated with the Seaway Crude Pipeline System to allow for access to Houston-area refineries, existing export facilities, the SPOT project and other facilities in the future.

### GAS TRANSMISSION AND MIDSTREAM

- **Rio Bravo Pipeline** – the Rio Bravo Pipeline is designed to transport up to 4.5 billion cubic feet per day (bcf/d) of natural gas from the Agua Dulce supply area to NextDecade Corporation's (NextDecade) Rio Grande liquefied natural gas (LNG) export facility in the Port of Brownsville, Texas. 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.

- **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 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 Environmental Impact Statement (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.
- **Valley Crossing Expansion Project** – On January 10, 2022, we executed a precedent agreement with Texas LNG Brownsville LLC (Texas LNG) under which, via an expansion of our Valley Crossing Pipeline, we will provide 0.72 bcf/d firm transportation capacity to Texas LNG's proposed LNG liquefaction and export facility in the Port of Brownsville, Texas for a term of at least 20 years. Expansion of the pipeline will be subject to Texas LNG's export facility reaching a final investment decision.
- **Texas Eastern Venice Extension Project** - a reversal and expansion of Texas Eastern's Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern's Larose compressor station. The project is expected to deliver 1.26 bcf/d of feed gas to Venture Global's proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The expansion will be subject to the Plaquemines LNG export facility reaching a final investment decision.

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 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.

Material contractual obligations arising in the normal course of business primarily consist of long-term contracts, annual debt maturities and related interest obligations, rights-of-way and leases. See Part II. *Item 8. Financial Statements and Supplementary data - Note 18 - Debt and Note 27 - Leases* for amounts outstanding at December 31, 2021, related to debt and leases.

Long-term contracts are contracts that we have signed for the purchase of services, pipe and other materials totaling \$5.9 billion which are expected to be paid over the next five years. Long-term contracts also consists of the following purchase obligations: gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.

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. On January 19, 2022, we closed a \$750 million private placement offering of non-call 10-year fixed-to-fixed subordinated notes which mature on January 19, 2032. The net proceeds from the offering will be used to redeem the Preference Shares, Series 17 at par on March 1, 2022.

### 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. In accordance with our funding plan, we completed the following long-term debt issuances totaling US\$3.9 billion and \$3.2 billion in 2021:

Entity	Issuance Date	Type of Issuance	Amount
<i>(in millions of Canadian dollars, unless stated otherwise)</i>			
Enbridge Inc.	February 2021	Floating rate senior-notes	US\$500
Enbridge Inc.	June 2021	Sustainability-linked senior notes	US\$1,000
Enbridge Inc.	June, October 2021	Senior notes	US\$2,000
Enbridge Inc.	September 2021	Medium-term notes	\$1,100
Enbridge Inc.	September 2021	Sustainability-linked medium-term	\$400
Enbridge Gas Inc.	September 2021	Medium-term notes	\$900
Enbridge Pipelines Inc.	May 2021	Medium-term notes	\$800
Spectra Energy Partners, LP <sup>1</sup>	September 2021	Senior notes	US\$400

<sup>1</sup> Issued through Texas Eastern, a wholly-owned operating subsidiary of SEP.

### Credit Facilities, Ratings 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 at December 31, 2021:

	Maturity <sup>1</sup>	Total Facilities	Draws <sup>2</sup>	Available
<i>(millions of Canadian dollars)</i>				
Enbridge Inc.	2022-2026	9,137	7,837	1,300
Enbridge (U.S.) Inc.	2023-2026	6,948	4,845	2,103
Enbridge Pipelines Inc.	2023	3,000	667	2,333
Enbridge Gas Inc.	2023	2,000	1,515	485
<b>Total committed credit facilities</b>		<b>21,085</b>	<b>14,864</b>	<b>6,221</b>

<sup>1</sup> Maturity date is inclusive of the one-year term out option for certain credit facilities.

<sup>2</sup> 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 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.

On February 10, 2022 we renewed our three year \$1.0 billion sustainability-linked credit facility, extending the maturity date out to July 2025.

In addition to the committed credit facilities noted above, we maintain \$1.3 billion of uncommitted demand letter of credit facilities, of which \$854 million was unutilized as at December 31, 2021. As at December 31, 2020, we had \$849 million of uncommitted demand letter of credit facilities, of which \$533 million was unutilized.

As at December 31, 2021, our net available liquidity totaled \$6.5 billion (2020 - \$12.7 billion), consisting of available credit facilities of \$6.2 billion (2020 - \$12.3 billion) and unrestricted Cash and cash equivalents of \$286 million (2020 - \$452 million) 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 December 31, 2021, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Cash flow growth, proceeds from non-core asset dispositions, 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 \$34 million, as reported on the Consolidated Statements of Financial Position, primarily includes cash collateral and future pipeline abandonment costs collected and held in trust. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative use by us.

Excluding current maturities of long-term debt, as at December 31, 2021 and 2020, we had a negative working capital position of \$3.1 billion and \$3.7 billion, respectively. In both periods, the major contributing factor to the negative working capital position was the current liabilities associated with 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

Year ended December 31, (millions of Canadian dollars)	2021	2020	2019
Operating activities	9,256	9,781	9,398
Investing activities	(10,657)	(5,177)	(4,658)
Financing activities	1,236	(4,770)	(4,745)
Effect of translation of foreign denominated cash and cash equivalents and restricted cash	(5)	(20)	44
Net increase/(decrease) in cash and cash equivalents and restricted cash	(170)	(186)	39

Significant sources and uses of cash for the years ended December 31, 2021 and 2020 are summarized below:

### Operating Activities

Typically, the primary factors impacting cash flow from operating activities year-over-year include changes in our operating assets and liabilities in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 28. Changes in Operating Assets and Liabilities.* Cash provided by operating activities is also impacted by changes in earnings and certain unusual, infrequent and other non-operating factors, as discussed under *Results of Operations.*

### Investing Activities

We continue 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.

A summary of additions to property, plant and equipment for the years ended December 31, 2021, 2020 and 2019 is set out below:

Year ended December 31, (millions of Canadian dollars)	2021	2020	2019
Liquids Pipelines	4,051	2,032	2,548
Gas Transmission and Midstream	2,353	2,066	1,695
Gas Distribution and Storage	1,343	1,134	1,100
Renewable Power Generation	16	81	23
Energy Services	1	2	2
Eliminations and Other	54	90	124
Total capital expenditures	7,818	5,405	5,492

### 2021

The increase in cash used in investing activities primarily resulted from the following factors:

- Our acquisition of Moda on October 12, 2021 and higher capital expenditures related to the completion of the US L3R Program, partially offset by higher proceeds received from dispositions in 2021 compared with 2020 due to the sale of our interest in Noverco on December 30, 2021.

### 2020

The increase in cash used in investing activities primarily resulted from the following factors:

- Lower proceeds from asset dispositions in 2020 compared with 2019, primarily due to the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses assets on December 31, 2019.

- The factor above was partially offset by lower contributions to the Gray Oak Holdings LLC equity investment in 2020, higher return of capital primarily from equity investments in Seaway Crude Holdings LLC, MarEn Bakken Company LLC, Gray Oak Holdings LLC and Enbridge Renewable Infrastructure Investments S.a.r.l., and lower net cash invested in affiliate loans in 2020 compared with 2019.

### **Financing Activities**

Cash provided by and used in financing activities primarily relates to issuances and repayments of external debt, as well as transactions with our common and preference shareholders relating to dividends, share issuances and share redemptions. Cash from financing activities is also impacted by changes in distributions to, and contributions from, noncontrolling interests.

#### **2021**

The increase in cash provided by financing activities primarily resulted from the following factors:

- Increased issuances of long-term debt, commercial paper and credit facility draws and short-term borrowings, along with lower repayments of long-term debt in 2021 compared to 2020.
- The factors above were partially offset by the redemption of Westcoast Energy Inc.'s (Westcoast) preferred shares in 2021 and increased common share dividend payments primarily due to the increase in our common share dividend rate.

#### **2020**

Cash used in financing activities in 2020 was consistent with 2019 due to the following factors:

- Increased commercial paper and credit facility draws, increased short-term borrowings and lower repayments of long-term debt in 2020 compared with 2019, partially offset by lower issuances of long-term debt.
- The absence in 2020 of the redemption of Westcoast's preferred shares in 2019.
- The above factors were partially offset by increased common share dividend payments primarily due to the increase in our common share dividend rate.

### **OFF-BALANCE SHEET ARRANGEMENTS**

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Part II. *Item 8. Financial Statements and Supplementary Data - Note 31 Guarantees* for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings of certain subsidiaries, non-consolidated entities or less than 100%-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on our Consolidated Statements of Financial Position. The possibility of us having to honor our contingencies is largely dependent upon the future operations of our subsidiaries, investees and other third parties, or the occurrence of certain future events. Issuance of these guarantee arrangements is not required for the majority of our operations.

We do not have material off-balance sheet financing entities or structures, except for guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, see Part II. *Item 8. Financial Statements and Supplementary Data - Note 30 Commitments and Contingencies* and *Note 31 Guarantees*.

We do not have material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

## Preference Share Issuances

Since July 2011, we have issued 315 million preference shares for gross proceeds of approximately \$7.9 billion with the following characteristics:

	Gross Proceeds	Dividend Rate	Dividend <sup>1</sup>	Per Share Base Redemption Value <sup>2</sup>	Redemption and Conversion Option Date <sup>2,3</sup>	Right to Convert Into <sup>3,4</sup>
<i>(Canadian dollars, unless otherwise stated)</i>						
Series A	\$125 million	5.50 %	\$1.37500	\$25	—	—
Series B	\$457 million	3.42 %	\$0.85360	\$25	June 1, 2022	Series C
Series C <sup>5</sup>	\$43 million	3-month treasury bill plus 2.40%	—	\$25	June 1, 2022	Series B
Series D	\$450 million	4.46 %	\$1.11500	\$25	March 1, 2023	Series E
Series F	\$500 million	4.69 %	\$1.17224	\$25	June 1, 2023	Series G
Series H	\$350 million	4.38 %	\$1.09400	\$25	September 1, 2023	Series I
Series J	US\$200 million	4.89 %	US\$1.22160	US\$25	June 1, 2022	Series K
Series L	US\$400 million	4.96 %	US\$1.23972	US\$25	September 1, 2022	Series M
Series N	\$450 million	5.09 %	\$1.27152	\$25	December 1, 2023	Series O
Series P	\$400 million	4.38 %	\$1.09476	\$25	March 1, 2024	Series Q
Series R	\$400 million	4.07 %	\$1.01825	\$25	June 1, 2024	Series S
Series 1	US\$400 million	5.95 %	US\$1.48728	US\$25	June 1, 2023	Series 2
Series 3	\$600 million	3.74 %	\$0.93425	\$25	September 1, 2024	Series 4
Series 5	US\$200 million	5.38 %	US\$1.34383	US\$25	March 1, 2024	Series 6
Series 7	\$250 million	4.45 %	\$1.11224	\$25	March 1, 2024	Series 8
Series 9	\$275 million	4.10 %	\$1.02424	\$25	December 1, 2024	Series 10
Series 11	\$500 million	3.94 %	\$0.98452	\$25	March 1, 2025	Series 12
Series 13	\$350 million	3.04 %	\$0.76076	\$25	June 1, 2025	Series 14
Series 15	\$275 million	2.98 %	\$0.74576	\$25	September 1, 2025	Series 16
Series 17	\$750 million	5.15 %	\$1.28750	\$25	March 1, 2022	Series 18
Series 19	\$500 million	4.90 %	\$1.22500	\$25	March 1, 2023	Series 20

1 The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board of Directors. With the exception of Series A and Series C Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 and Series 19 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15% and 4.90%, respectively. No other series of Preference Shares has this feature.

2 Series A Preference Shares may be redeemed any time at our option. For all other series of Preference Shares, we may at our option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.

4 With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: \$25 x (number of days in quarter/number of days in a year) x three-month Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), 4.1% (Series 18) or 3.2% (Series 20); or US\$25 x (number of days in quarter/number of days in a year) x three-month US Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).

5 The floating quarterly dividend amount for the Series C Preference Shares was increased to \$0.15501 from \$0.15349 on March 1, 2021, was increased to \$0.15753 from \$0.15501 on June 1, 2021, was increased to \$0.16081 from \$0.15753 on September 1, 2021 and was decreased to \$0.15719 from \$0.16081 on December 1, 2021, due to reset on a quarterly basis following the issuance thereof.

## PREFERENCE SHARE REDEMPTION

We intend to exercise our right to redeem all of our outstanding cumulative redeemable minimum rate reset preference shares, Series 17, on March 1, 2022 at a price of \$25 per Series 17 share, together with all accrued and unpaid dividends, if any.

## Dividends

We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2021, we announced a 3% increase in our quarterly dividend to \$0.86 per common share, or \$3.44 annualized, effective with the dividend payable on March 1, 2022, thereby making a dividend increase for 27 straight years.

For the years ended December 31, 2021 and 2020, total dividends paid were \$6.8 billion and \$6.6 billion, respectively, all of which were paid in cash and reflected in financing activities.

On December 6, 2021, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2022 to shareholders of record on February 15, 2022.

	Dividend per share
Common Shares <sup>1</sup>	\$0.86000
Preference Shares, Series A	\$0.34375
Preference Shares, Series B	\$0.21340
Preference Shares, Series C <sup>2</sup>	\$0.15719
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

<sup>1</sup> The quarterly dividend per common share was increased 3% to \$0.86 from \$0.835, effective March 1, 2022.

<sup>2</sup> The quarterly dividend per share paid on Series C was increased to \$0.15501 from \$0.15349 on March 1, 2021, was increased to \$0.15753 from \$0.15501 on June 1, 2021, was increased to \$0.16081 from \$0.15753 on September 1, 2021 and was decreased to \$0.15719 from \$0.16081 on December 1, 2021, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.

## 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 <sup>1</sup>	EEP Notes <sup>2</sup>
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

<sup>1</sup> As at December 31, 2021, the aggregate outstanding principal amount of SEP notes was approximately US\$3.2 billion.

<sup>2</sup> As at December 31, 2021, the aggregate outstanding principal amount of EEP notes was approximately US\$2.4 billion.

## Enbridge Notes under Guarantees

US Dollar Denominated <sup>1</sup>	Canadian Dollar Denominated <sup>2</sup>
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
0.550% Senior Notes due 2023	3.950% Senior Notes due 2024
3.500% Senior Notes due 2024	2.440% Senior Notes due 2025
2.500% Senior Notes due 2025	3.200% Senior Notes due 2027
4.250% Senior Notes due 2026	6.100% Senior Notes due 2028
1.600% Senior Notes due 2026	2.990% Senior Notes due 2029
3.700% Senior Notes due 2027	7.220% Senior Notes due 2030
3.125% Senior Notes due 2029	7.200% Senior Notes due 2032
2.500% Sustainability-linked Senior Notes due 2033	3.100% Sustainability-linked Senior Notes due 2033
4.500% Senior Notes due 2044	5.570% Senior Notes due 2035
5.500% Senior Notes due 2046	5.750% Senior Notes due 2039
4.000% Senior Notes due 2049	5.120% Senior Notes due 2040
3.400% Senior Notes due 2051	4.240% Senior Notes due 2042
	4.570% Senior Notes due 2044
	4.870% Senior Notes due 2044
	4.100% Senior Notes due 2051
	4.560% Senior Notes due 2064

<sup>1</sup> As at December 31, 2021, the aggregate outstanding principal amount of the Enbridge US dollar denominated notes was approximately US\$11 billion.

<sup>2</sup> As at December 31, 2021, the aggregate outstanding principal amount of the Enbridge Canadian dollar denominated notes was approximately \$9.2 billion.

Rule 3-10 of the US Securities and Exchange Commission's (SEC) Regulation S-X provides an exemption from the reporting requirements of the Securities Exchange Act of 1934, as amended (Exchange Act) for fully consolidated subsidiary issuers of guaranteed securities and subsidiary guarantors and allows for summarized financial information in lieu of filing separate financial statements for each of the Partnerships.

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

### Summarized Combined Statement of Earnings

	Year ended December 31, 2021
<i>(millions of Canadian dollars)</i>	
Operating loss	(64)
Earnings	4,970
Earnings attributable to common shareholders	4,604

## Summarized Combined Statements of Financial Position

	December 31, 2021	December 31, 2020
<i>(millions of Canadian dollars)</i>		
Accounts receivable from affiliates	3,442	2,108
Short-term loans receivable from affiliates	4,947	4,926
Other current assets	605	375
Long-term loans receivable from affiliates	51,983	43,217
Other long-term assets	3,732	4,237
Accounts payable to affiliates	1,982	1,267
Short-term loans payable to affiliates	2,891	4,117
Other current liabilities	8,110	5,628
Long-term loans payable to affiliates	41,370	32,035
Other long-term liabilities	41,353	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 or other equity interests in that Partnership as a result of which the Partnership ceases to be a consolidated subsidiary of Enbridge;
- the merger of that Partnership into Enbridge or the other Partnership or the liquidation and dissolution of that Partnership;
- the repayment in full or discharge or defeasance of those Guaranteed Enbridge Notes, as contemplated by the applicable indenture or guarantee agreement;

- with respect to EEP, the repayment in full or discharge or defeasance of each of the consenting EEP notes listed above;
- with respect to SEP, the repayment in full or discharge or defeasance of each of the consenting SEP notes listed above; or
- with respect to any series of Guaranteed Enbridge Notes, with the consent of holders of at least a majority of the outstanding principal amount of that series of Guaranteed Enbridge Notes.

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

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

## LEGAL AND OTHER UPDATES

### 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”. On December 15, 2021, we removed the case to the US District Court in the Western District of Michigan (US District Court), where it was assigned to Judge Janet T. Neff. The removal of the Attorney General’s case to federal court follows a November 16, 2021 ruling (further described below) which held that the similar (and now dismissed) 2020 lawsuit brought by the Governor to force Line 5’s shutdown raised important federal issues that should be heard in federal court. On December 21, 2021, the Attorney General made a request to file a remand motion and on December 28, 2021, we responded to her request to file that motion. On January 5, 2022, the court issued an Order allowing the Attorney General to file a motion to remand the 2019 case. The Attorney General’s motion and brief was filed on January 14, 2022, and our response is due on February 11, 2022. The motion is expected to be fully briefed by March 2022.

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 demanded 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. US District Court Judge Neff was assigned to the cases and on November 16, 2021, Judge Neff issued an order denying the State’s motion to remand its 2020 case back to Ingham County Circuit Court, finding that the case should remain in federal court. Judge Neff also ruled in our favor on our motion for additional briefing and granted the Government of Canada’s motion to file a supplemental brief, which reiterated that the 1977 Transit Pipelines Treaty between the US and Canada had been invoked in October and that the matter is of great importance to Canada. Subsequently, the Governor voluntarily dismissed the State’s lawsuit on November 30, 2021.

Our lawsuit to prohibit the Governor of Michigan and Director of the Michigan Department of Natural Resources from interfering with the operation of Line 5, remains in federal court. On November 30, 2021 the State made a request to Judge Neff to file a motion to dismiss the complaint. On the same date, we made a request to file a motion for summary judgment. Briefing on these motions began on January 18, 2022 and is scheduled to be complete by April 2022.

In 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 continue to actively pursue 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 (MPSC). The EGLE permits were granted in the first quarter of 2021; one of the EGLE permits was challenged by the Bay Mills Indian Community. Dispositive motions are fully briefed and with the Administrative Law Judge for decision.

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.

In the MPSC contested case proceeding, testimony has been filed, and the hearing took place during January 2022, with briefing scheduled to be complete by March 2022.

### **Dakota Access Pipeline**

We own an effective interest of 27.6% in the Bakken Pipeline System, which is inclusive of 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. Dakota Access, LLC has since filed a petition asking the US Supreme Court to review the decision that an EIS is required. 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 September 20, 2021, DAPL requested that the US Supreme Court review the US Court of Appeals decision. That request, opposed by the US Government and the Tribes, remands pending.

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 also granted the request from the Tribes to extend 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.

#### **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.

### **CRITICAL ACCOUNTING ESTIMATES**

Our consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (US GAAP), which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

#### **Business Combinations**

We apply the provisions of Accounting Standards Codification (ASC) 805 *Business Combinations* in accounting for our acquisitions. The acquired long-lived assets, intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Goodwill represents the excess of the purchase price over the fair value of net assets. While we use our best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, our estimates are inherently uncertain and subject to refinement. During the measurement period, which may be up to one year from the acquisition date, we record adjustments to the assets acquired and liabilities assumed with the corresponding offset to goodwill. Upon the conclusion of the measurement period or final determination of values of assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded to our consolidated statements of operations.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, we utilize a variety of factors including market data, historical and future expected cash flows, growth rates and discount rates. The subjective nature of our assumptions increases the risk associated with estimates surrounding the projected performance of the acquired entity.

#### **Goodwill Impairment**

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

We perform our impairment assessment annually on April 1 at the reporting unit level. Reporting units are determined by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar.

We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment assessment. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends, and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed.

The quantitative goodwill impairment assessment involves determining the fair value of our reporting units and comparing those values to the carrying value of each corresponding reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. Fair value of our reporting units is estimated using a combination of discounted cash flow models and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections include significant judgments and assumptions relating to discount rates and expected future capital expenditures. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

Our most recent annual assessment of the goodwill balance was performed on April 1, 2021. As at April 1, 2021, our reporting units were equivalent to our reportable segments. We performed a quantitative goodwill impairment assessment for the Gas Transmission and Midstream reporting unit and qualitative assessments for the Liquids Pipelines and Gas Distribution and Storage reporting units. Our goodwill impairment assessments did not result in an impairment charge. Also, we did not identify any indicators of goodwill impairment during the remainder of 2021.

### **Asset Impairment**

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value.

With respect to equity method investments, we assess at each balance sheet date whether there is objective evidence that the investment is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we determine whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the investment.

Asset fair value is determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the asset and the recognition of an impairment loss in the Consolidated Statements of Earnings.

### **Assets Held for Sale**

We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

### **Regulatory Accounting**

Certain of our businesses are subject to regulation by various authorities, including but not limited to, the CER, the FERC, the Alberta Energy Regulator, La Régie de l'énergie du Québec and the OEB. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under US GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- Costs of providing service, including operating costs, capital invested, depreciation expense and taxes;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Interest costs on the debt component of the capital structure; and
- Contract and volume throughput assumptions.

The allowed rate of return is determined in accordance with the applicable regulatory model and may impact our profitability. The rates for a number of our projects are based on a cost-of-service recovery model that follows the regulators' authoritative guidance. Under the cost-of-service tolling methodology, we calculate tolls based on forecast volumes and cost. A difference between forecast and actual results causes an over or under recovery in any given year. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the CER's Land Matters Consultation Initiative (LMCI) and for future removal and site restoration costs as approved by the OEB.

To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

As at December 31, 2021 and 2020, our regulatory assets totaled \$5.9 billion and \$5.6 billion, respectively, and regulatory liabilities totaled \$3.4 billion and \$3.4 billion, respectively.

## Depreciation

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2021 and 2020, of \$100.1 billion and \$94.6 billion, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

## Pension and Other Postretirement Benefits

We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and, therefore, could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the December 31, 2021 Consolidated Financial Statements of a 0.5% change in key pension and other postretirement benefit obligations (OPEB) assumptions:

	Canada		United States	
	Obligation	Expense	Obligation	Expense
<i>(millions of Canadian dollars)</i>				
<b>Pension</b>				
Decrease in discount rate	378	31	70	5
Decrease in expected return on assets	—	21	—	5
Decrease in rate of salary increase	(71)	(15)	(6)	(2)
<b>OPEB</b>				
Decrease in discount rate	21	1	8	—
Decrease in expected return on assets	N/A	N/A	—	1

### **Contingent Liabilities**

Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies*. In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

### **Asset Retirement Obligations**

Asset Retirement Obligations (ARO) associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. The discount rates used to estimate the present value of the expected future cash flows for the year ended December 31, 2021 ranged from 0.9% to 9.0% (2020 - 1.8% to 9.0%). ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2009, the CER issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the CER Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The CER's decision stated that while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the CER. Following the CER's final approval of the collection mechanism and the set-aside mechanism for LMCI, we began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trust in accordance with the CER decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

The Minnesota Public Utilities Commission (MPUC), in its June 28, 2018 decision granting the Line 3 Replacement Project's Certificate of Need, required Enbridge to establish and fund a decommissioning trust (Decommissioning Trust Fund) for the purpose of funding the cost of retiring Line 3 Replacement Project assets at the end of their useful lives. Further to the Certificate of Need decision, in late 2021 the MPUC established a process for the purpose of determining the terms and conditions of the Decommissioning Trust Fund. Enbridge anticipates this MPUC process to be completed in 2022, with a decision from the MPUC in the second half of 2022. Enbridge expects to recover contributions necessary to fund the Decommissioning Trust Fund from its shippers through rates.

## **CHANGES IN ACCOUNTING POLICIES**

Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 3. Changes in Accounting Policies*.