Quarterly Report to Shareholders

TC Energy reports strong third quarter financial results
Well positioned to fund $30 billion capital program without additional common equity

CALGARY, Alberta – **November 1, 2019** – TC Energy Corporation (TSX, NYSE: TRP) (TC Energy or the Company) today announced net income attributable to common shares for third quarter 2019 of $739 million or $0.79 per share compared to net income of $928 million or $1.02 per share for the same period in 2018. Comparable earnings for third quarter 2019 were $970 million or $1.04 per common share compared to $902 million or $1.00 per common share in 2018. TC Energy's Board of Directors also declared a quarterly dividend of $0.75 per common share for the quarter ending December 31, 2019, equivalent to $3.00 per common share on an annualized basis. Commencing with the dividends declared October 31, 2019, the Company discontinued the practice of issuing common shares from treasury at a discount to satisfy purchases under its Dividend Reinvestment Plan (DRP).

"During the third quarter of 2019, our diversified portfolio of regulated and long-term contracted assets continued to perform very well," said Russ Girling, TC Energy's President and Chief Executive Officer. "Despite significant asset sales that have accelerated the strengthening of our balance sheet, comparable earnings per share increased four per cent compared to the same period last year while comparable funds generated from operations of $1.8 billion were 15 per cent higher. The increases reflect the robust performance of our legacy assets and contributions from the approximately $8.2 billion of growth projects that have entered service to date in 2019. Those increases were partially offset by lower contributions from approximately $3.4 billion of assets that were monetized during the first nine months of the year."

The asset sales included the Coolidge gas-fired power plant in Arizona, certain Columbia Midstream assets and an 85 per cent equity interest in Northern Courier. In addition, the Company has entered into an agreement to sell its Ontario gas-fired power plants including Napanee, Halton Hills and a 50 per cent interest in Portlands Energy Centre for approximately $2.87 billion. Including this transaction, which is anticipated to close in first quarter 2020, proceeds from asset sales are expected to total approximately $6.3 billion.

"Each of these transactions allowed us to surface significant value and redeploy the proceeds into our $30 billion secured capital program, thereby reducing our need for external funding including common equity," added Girling. "When combined with our significant internally generated cash flow and access to debt capital markets, we are well positioned to prudently fund our capital program in a manner that maximizes earnings and cash flow per share and is consistent with achieving targeted run-rate credit metrics including debt-to-EBITDA in the high four times area. As a result, we do not expect to issue any additional common shares from treasury under our Dividend Reinvestment Plan commencing with fourth quarter 2019 dividends."

Looking forward, TC Energy also continues to progress more than $20 billion of projects under development including Keystone XL and the Bruce Power life extension program. Success in advancing these and other growth initiatives that are expected to emanate from our five operating businesses across North America could extend our current dividend growth outlook of eight to 10 per cent through 2021.

Highlights

(All financial figures are unaudited and in Canadian dollars unless otherwise noted)

- Third quarter 2019 financial results
  - Net income attributable to common shares of $739 million or $0.79 per common share
  - Comparable earnings of $970 million or $1.04 per common share
  - Comparable earnings before interest, taxes, depreciation and amortization of $2.3 billion
  - Net cash provided by operations of $1.6 billion
  - Comparable funds generated from operations of $1.8 billion
  - Comparable distributable cash flow of $1.7 billion or $1.78 per common share
- Declared a quarterly dividend of $0.75 per common share for the quarter ending December 31, 2019
- Discontinued practice of issuing common shares from treasury at a discount to satisfy purchases under DRP commencing with the dividends declared October 31
- Announced $1.2 billion West Path Delivery Program, an expansion of the NGTL and Foothills pipeline systems
- Initiated the US$0.3 billion Gas Transmission Northwest (GTN) XPress project
- Commenced commercial operations on the Sur de Texas pipeline in September
- Continued construction activities on the $6.6 billion Coastal GasLink pipeline project and advanced funding plans for the project
- Received Nebraska Supreme Court decision in August affirming the approval of the Keystone XL pipeline route through Nebraska
- Received Draft Supplemental Environmental Impact Statement (DSEIS) for the Keystone XL project in October
- Closed the sale of certain Columbia Midstream assets for approximately US$1.3 billion
- Completed the partial monetization of Northern Courier for aggregate gross proceeds of approximately $1.15 billion
- Entered into an agreement to sell our interests in three Ontario natural gas-fired power plants for approximately $2.87 billion
- Issued $1.0 billion of long-term fixed-rate Medium Term Notes in September 2019
- Issued US$1.1 billion of Junior Subordinated Notes in September 2019.

Net income attributable to common shares decreased by $189 million or $0.23 per common share to $739 million or $0.79 per share for the three months ended September 30, 2019 compared to the same period last year. Per share results reflect the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate At-The-Market (ATM) program in 2018. Third quarter 2019 results included an after-tax loss of $133 million at September 30, 2019 related to the Ontario natural gas-fired power plants held for sale, an after-tax loss of $133 million related to the sale of certain Columbia Midstream assets in August 2019 and an after-tax gain of $115 million related to the partial sale of Northern Courier in July 2019. Third quarter 2018 results included after-tax income of $8 million related to our U.S. Northeast power marketing contracts. These specific items, as well as unrealized gains and losses from changes in risk management activities, are excluded from comparable earnings.

Comparable EBITDA increased by $288 million for the three months ended September 30, 2019 compared to the same period in 2018 primarily due to the net effect of the following:

- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities, partially offset by the sale of an 85 per cent equity interest in Northern Courier in July 2019
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by decreased earnings from Bison (wholly-owned by TC PipeLines, LP) and from the sale of certain Columbia Midstream assets in August 2019
- higher contribution from Canadian Natural Gas Pipelines mainly due to the Canadian Mainline recovery of increased depreciation and higher incentive earnings in 2019

- higher contribution from Power and Storage primarily due to increased Bruce Power results from a higher realized power price and higher output, partially offset by the sale of our interests in the Cartier Wind power facilities in fourth quarter 2018 and the sale of our Coolidge generating station in May 2019.

Comparable earnings increased by $68 million or $0.04 per common share for the three months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher income tax expense primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials
- higher depreciation, largely in Canadian Natural Gas Pipelines which is fully recovered in tolls as reflected in the comparable EBITDA discussion above, therefore having no impact on comparable earnings. In addition, higher consolidated depreciation reflects new projects placed in service
- lower AFUDC in U.S. Natural Gas Pipelines primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by continued investment in our NGTL System expansion and Mexico projects.

Comparable earnings per common share for the three months ended September 30, 2019 also reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Notable recent developments include:

Canadian Natural Gas Pipelines:

- *NGTL System*: On October 31, 2019, we announced our West Path Delivery Program, an expansion of our NGTL System and Foothills pipeline system for incremental export capacity onto the GTN system in the Pacific Northwest. The Canadian portion of the expansion program has an estimated capital cost of $1.2 billion and consists of approximately 119 km (74 miles) of pipeline and associated facilities with in-service dates between fourth quarter 2022 and fourth quarter 2023. This Program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm service contracts with terms that exceed 30 years.

  In the nine months ended September 30, 2019, the NGTL System placed approximately $0.8 billion of capacity projects in service.

  On March 14, 2019, the NGTL System Rate Design and Services Application was filed with the National Energy Board (NEB) which included a settlement agreement negotiated with members of its Tolls, Tariff, Facilities and Procedures (TTFP) committee which represents stakeholders. The settlement is supported by the majority of members of the TTFP committee. The Application addresses rate design, terms and conditions of service for the NGTL System and a tolling methodology for the North Montney Mainline (NMML). Given the complexity of the issues raised in the Application, the NEB decided to hold a public hearing which is expected to conclude in fourth quarter 2019.

  On May 16, 2019, the NEB approved the proposed NMML tolling methodology including the surcharge, as filed, on an interim basis, pending the outcome of the above Rate Design and Services Application.

- *Coastal GasLink Pipeline Project:* Following the October 2018 positive Final Investment Decision (FID) by LNG Canada, construction activities continue along the pipeline route including the area south of Houston, B.C. which required a B.C. Supreme Court injunction for access. We expect a further decision in fourth quarter 2019 from the B.C. Supreme Court to extend the injunction to project completion.

  On July 26, 2019, the NEB issued its decision affirming provincial jurisdiction for Coastal GasLink. Accordingly, construction will continue to proceed as planned under the permits granted to Coastal GasLink by the B.C. Oil and Gas Commission.

Our estimated project cost has increased from $6.2 billion to $6.6 billion due to increased scope and refinement of construction estimates for rock work and watercourse crossings. We expect the incremental cost will be incorporated into the final tolls.

TC Energy continues to advance funding plans for this pipeline project through a combination of the sale of up to 75 per cent ownership interest and arrangement of project financing, which are both proceeding as planned.

U.S. Natural Gas Pipelines:

- *GTN XPress:* In third quarter 2019, we initiated the GTN XPress project which is an integrated reliability and expansion project on the GTN system that will provide for the transport of additional volumes enabled by the West Path Delivery Program discussed above. GTN XPress is expected to be fully complete in late 2023 with an estimated total cost of US$0.3 billion.
- *Louisiana XPress and Grand Chenier XPress:* Combined, the Louisiana XPress and Grand Chenier XPress projects will connect nearly 2 Bcf/d of supply to Gulf Coast LNG export facilities. Both projects have now obtained necessary customer approvals or waivers of conditions allowing the projects to move to the execution phase. Interim service for Louisiana XPress shippers will commence on Columbia Gulf November 1, 2019 with full in-service anticipated in 2022 and total estimated project costs of US$0.4 billion. The anticipated in-service dates for Grand Chenier XPress are in 2021 and 2022 for Phase I and II, respectively, with total estimated project costs of US$0.2 billion.
- *Sale of Columbia Midstream Assets:* On August 1, 2019, we finalized the sale of certain Columbia Midstream assets to UGI Energy Services, LLC, a subsidiary of UGI Corporation, for proceeds of approximately US$1.3 billion, before post-closing adjustments. The sale resulted in a pre-tax gain of $21 million ($133 million after-tax loss), which included the release of $595 million of Columbia's goodwill allocated to these assets that is not deductible for income tax purposes. This sale does not include any interest in Columbia Energy Ventures Company, which is our minerals business in the Appalachian basin.
- *Columbia Gulf Rate Settlement:* Columbia Gulf and its shippers have recently agreed to a settlement-in-principle addressing all rate and service related issues raised during the settlement discussions. We plan to file an agreement with the Federal Energy Regulatory Commission (FERC) before the end of the year reflecting this settlement-in-principle and precluding the need to file a general rate case as contemplated by Columbia Gulf's previous 2016 settlement. We anticipate that FERC will accept the settlement agreement and that it will be unopposed.

Mexico Natural Gas Pipelines:

- *CFE Arbitration:* In June 2019, Comisión Federal de Electricidad (CFE) filed requests for arbitration under the Sur de Texas, Villa de Reyes and Tula contracts. CFE requested nullification of clauses that govern the parties' responsibilities in instances of force majeure and requested reimbursement of certain fixed capacity payments. Regarding Sur de Texas, the parties successfully executed an amending agreement as described below and CFE has withdrawn its Sur de Texas arbitration request.

  Negotiations continue with respect to the Villa de Reyes and Tula arbitrations with the expectation of reaching agreements before the end of 2019. Accordingly, these arbitration proceedings have been temporarily suspended while negotiations continue.

- *Sur de Texas:* In September 2019, the Sur de Texas pipeline began commercial operations following execution of the above amending agreement with CFE. The original Sur de Texas agreement had a fluctuating toll profile over a 25-year contract term. As a result of the amendment, the contract has been extended and CFE will now receive transportation services for 35 years under a levelized toll structure based on actual construction costs with an initial fixed toll applicable for the first 25 years of the contract term and a higher fixed toll over the last 10 years of the contract. All other terms and conditions of the contract remain substantially unchanged. Monthly revenue for this pipeline will be recognized at a levelized average rate over the 35-year contract term.
- *Villa de Reyes:* Construction of the Villa de Reyes project is ongoing, however the project has experienced force majeure events that have delayed the schedule. We anticipate a phased in-service to commence in early 2020 and have received certain capacity payments under force majeure provisions in the contract, but have not commenced recording revenues.
- *Tula:* Construction on the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. The project in-service date is estimated to be two years after the Secretary of Energy successfully concludes such consultations. We have received certain capacity payments under force majeure provisions in the contract but have not commenced recording revenues.

Liquids Pipelines:

- *Northern Courier:* On July 17, 2019, we completed the sale of an 85 per cent equity interest in Northern Courier to Alberta Investment Management Corporation for gross proceeds of $144 million before post-closing adjustments, resulting in a pre-tax gain of $69 million after recording our remaining 15 per cent interest at fair value. On an after-tax basis, the gain of $115 million reflects the utilization of previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds from which were paid to TC Energy, resulting in aggregate gross proceeds to TC Energy of $1.15 billion from this asset monetization.

  We remain the operator of the Northern Courier pipeline and are using the equity method to account for our remaining 15 per cent interest in our Consolidated financial statements.
- *Keystone XL:* On June 27, 2019, the U.S. Government and TC Energy filed motions to dismiss the lawsuit brought by two U.S. Native American communities that have been expanded to challenge both the 2017 and 2019 Presidential Permits. The U.S. District Court in Montana heard argument on motions to dismiss the complaints on September 12, 2019 and a decision is expected by year end.

  On June 27, 2019, the U.S. Government filed a motion to dismiss the challenge to the 2019 Presidential Permit brought by the Indigenous Environmental Network. TC Energy has intervened and moved to dismiss this lawsuit. A hearing on the motion to dismiss and a motion for a preliminary injunction by the Indigenous Environmental Network was held by the U.S. District Court in Montana on October 9, 2019. A ruling is expected to be made by year end.

  On August 23, 2019, the Nebraska Supreme Court affirmed the November 2017 decision by the Nebraska Public Service Commission that approved the Keystone XL Pipeline route through the state. A motion for re-hearing of the decision has been denied.

  The U.S. Department of State issued a DSEIS for the project on October 4, 2019. The DSEIS supplements the 2014 Keystone XL SEIS. It considers changes in the project since 2014 including routing in Nebraska and incorporates updated information and new studies. The SEIS is expected to be issued by the end of 2019.

  We continue to actively manage legal and regulatory matters as the project advances.

Power and Storage (previously Energy):

- *Ontario Natural Gas-fired Power Plants:* On July 30, 2019, we entered into an agreement to sell our Halton Hills and Napanee power plants as well as our 50 per cent interest in Portlands Energy Centre to a subsidiary of Ontario Power Generation Inc. for proceeds of approximately $2.87 billion, subject to timing of the close and related adjustments. The sale is expected to close by the end of first quarter 2020 subject to conditions which include regulatory approvals and Napanee reaching commercial operations as outlined in the agreement. We expect this sale to result in a total pre-tax loss of approximately $330 million ($231 million after tax). As these assets have been classified as held for sale, $202 million of this pre-tax loss ($133 million after tax) has been recorded at September 30, 2019. The remaining loss primarily reflects the residual costs to be incurred until Napanee is placed in service, including capitalized interest, and will be recorded on or before closing of the transaction.

  In March 2019, Napanee experienced an equipment failure while progressing commissioning activities. Steps are being taken to address the situation and commercial operations are expected to commence in late first quarter 2020 with an estimated project cost of $1.8 billion.

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.75 per common share for the quarter ending December 31, 2019 on TC Energy's outstanding common shares. The quarterly amount is equivalent to $3.00 per common share on an annualized basis.
- *Issuance of Long-term Debt and Junior Subordinated Notes:* In September 2019, TransCanada PipeLines Limited issued $700 million of Medium Term Notes, due in September 2029, bearing interest at a fixed rate of 3.00 per cent, as well as an additional $300 million of Medium Term Notes, due July 2048, bearing interest at a fixed rate of 4.18 per cent.

  In September 2019, TransCanada Trust (the Trust), a wholly-owned financing trust subsidiary of TCPL, issued US$1.1 billion of Trust Notes – Series 2019-A to third party investors at a fixed interest rate of 5.50 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.1 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.75 per cent. The junior subordinated notes are callable at TCPL's option at any time on or after September 15, 2029 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

  The net proceeds of these issuances were used for general corporate purposes and to fund our capital program.
- *Dividend Reinvestment Plan:* In third quarter 2019, the DRP participation rate amongst common shareholders was approximately 35 per cent resulting in $247 million reinvested in common equity under the program. Year-to-date in 2019, the participation rate amongst common shareholders has been approximately 34 per cent resulting in $711 million of dividends reinvested.

  Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under TC Energy’s DRP will no longer be satisfied with shares issued from treasury at a discount, but rather will be acquired on the open market at 100 per cent of the weighted average purchase price. The DRP is available for dividends payable on TC Energy’s common and preferred shares.

Teleconference and Webcast:

We will hold a teleconference and webcast on Friday, November 1, 2019 to discuss our third quarter 2019 financial results. Russ Girling, President and Chief Executive Officer, Don Marchand, Executive Vice-President and Chief Financial Officer, and members of the executive leadership team will discuss TC Energy's third quarter financial results and company developments at 9 a.m. MDT / 11 a.m. EDT.

Members of the investment community and other interested parties are invited to participate by calling 800.478.9326 or 416.340.2218 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available on TC Energy's website at www.TCEnergy.com/events or via the following URL: www.gowebcasting.com/10366.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EST) on November 8, 2019. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 8633180#.

The unaudited interim Condensed consolidated financial statements and Management's Discussion and Analysis (MD&A) are available under TC Energy's profile on SEDAR at www.sedar.com**, with the U.S. Securities and Exchange Commission on EDGAR at** www.sec.gov/info/edgar.shtml **and on our website at** www.TCEnergy.com**.**

TC Energy and its affiliates deliver the energy millions of people rely on every day to power their lives and fuel industry. Focused on what we do and how we do it, we are guided by core values of safety, responsibility, collaboration and integrity. Our more than 7,000 people are committed to sustainably developing and operating pipeline, power generation and energy storage facilities across Canada, the United States and Mexico. TC Energy's common shares trade on the Toronto (TSX) and New York (NYSE) stock exchanges under the symbol TRP. Visit www.TCEnergy.com and connect with us on social media to learn more.

Forward Looking Information

This release contains certain information that is forward-looking and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TC Energy security holders and potential investors with information regarding TC Energy and its subsidiaries, including management's assessment of TC Energy's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TC Energy's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking information due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to the Quarterly Report to Shareholders dated October 31, 2019 and the 2018 Annual Report filed under TC Energy's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov.

Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable earnings per common share, comparable EBITDA, comparable distributable cash flow, comparable distributable cash flow per common share and comparable funds generated from operations, that do not have any standardized meaning as prescribed by U.S. GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable except as otherwise described in the Condensed consolidated financial statements and MD&A. For more information on non-GAAP measures, refer to TC Energy's Quarterly Report to Shareholders dated October 31, 2019.

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Quarterly report to shareholders

Third quarter 2019

Financial highlights

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Income				
Revenues	**3,133**	3,156	**9,992**	9,775
Net income attributable to common shares	**739**	928	**2,868**	2,447
per common share – basic and diluted	**$0.79**	$1.02	**$3.09**	$2.72
Comparable EBITDA[1]	**2,344**	2,056	**7,051**	6,110
Comparable earnings[1]	**970**	902	**2,881**	2,534
per common share[1]	**$1.04**	$1.00	**$3.11**	$2.82
Cash flows				
Net cash provided by operations	**1,585**	1,299	**5,256**	4,516
Comparable funds generated from operations[1]	**1,802**	1,571	**5,292**	4,641
Comparable distributable cash flow[1]	**1,657**	1,413	**4,830**	4,158
per common share[1]	**$1.78**	$1.56	**$5.21**	$4.63
Capital spending[2]	**2,135**	2,798	**6,429**	7,491
Dividends declared				
Per common share	**$0.75**	$0.69	**$2.25**	$2.07
Basic common shares outstanding (millions)				
– weighted average for the period	**932**	906	**927**	898
– issued and outstanding at end of period	**934**	914	**934**	914

1 Comparable EBITDA, comparable earnings, comparable earnings per common share, comparable funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. Refer to the Non-GAAP measures section for more information.

2 Includes capital expenditures, capital projects in development and contributions to equity investments.

Management's discussion and analysis

October 31, 2019

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation (TC Energy).

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TC Energy. It discusses our business, operations, financial position, risks and other factors for the three and nine months ended September 30, 2019, and should be read with the accompanying unaudited Condensed consolidated financial statements for the three and nine months ended September 30, 2019, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2018 audited Consolidated financial statements and notes and the MD&A in our 2018 Annual Report. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in our 2018 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are ***forward-looking*** are based on certain assumptions and on what we know and expect today and generally include words like ***anticipate, expect, believe, may, will, should, estimate*** or other similar words.

Forward-looking statements in this MD&A include information about the following, among other things:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected impact of future tax and accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- changes in environmental and other laws and regulations
- our ability to effectively anticipate and assess changes to government policies and regulations
- competition in the pipeline, power and storage sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in this MD&A and in other reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2018 Annual Report.

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TC Energy in our Annual Information Form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations
- comparable distributable cash flow
- comparable distributable cash flow per common share.

These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities.

Comparable measures

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Our decision not to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments to enacted tax rates
- gains or losses on sales of assets or assets held for sale
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of goodwill, investments and other assets
- acquisition and integration costs.

We exclude the unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

The following table identifies our non-GAAP measures against their most directly comparable GAAP measures.

Comparable measure	GAAP measure
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable funds generated from operations	net cash provided by operations
comparable distributable cash flow	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings adjusted for specific items. Comparable EBIT is an effective tool for evaluating trends in each segment.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings or losses attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income taxes, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Consolidated results section for reconciliations to net income attributable to common shares and net income per common share.

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating performance of our assets. Comparable funds generated from operations is adjusted for the cash impact of specific items. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

Comparable distributable cash flow and comparable distributable cash flow per common share

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and non-recoverable maintenance capital expenditures.

Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts paid for our proportionate share of maintenance capital expenditures on our equity investments. We have the opportunity to recover effectively all of our pipeline maintenance capital expenditures in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines through tolls. As such, our presentation of comparable distributable cash flow and comparable distributable cash flow per common share only includes a reduction for non-recoverable maintenance capital expenditures in their respective calculations.

Refer to the Financial condition section for a reconciliation to net cash provided by operations.

Consolidated results – third quarter 2019

As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Canadian Natural Gas Pipelines	**283**	267	**794**	800
U.S. Natural Gas Pipelines	**626**	545	**2,081**	1,734
Mexico Natural Gas Pipelines	**125**	127	**354**	382
Liquids Pipelines	**491**	316	**1,493**	1,047
Power and Storage	**27**	223	**353**	464
Corporate	**33**	(68)	**(1)**	(77)
Total segmented earnings	**1,585**	1,410	**5,074**	4,350
Interest expense	**(573)**	(577)	**(1,747)**	(1,662)
Allowance for funds used during construction	**120**	147	**358**	365
Interest income and other	**(19)**	168	**250**	139
Income before income taxes	**1,113**	1,148	**3,935**	3,192
Income tax expense	**(274)**	(120)	**(727)**	(394)
Net income	**839**	1,028	**3,208**	2,798
Net income attributable to non-controlling interests	**(59)**	(59)	**(217)**	(229)
Net income attributable to controlling interests	**780**	969	**2,991**	2,569
Preferred share dividends	**(41)**	(41)	**(123)**	(122)
Net income attributable to common shares	**739**	928	**2,868**	2,447
Net income per common share – basic and diluted	**$0.79**	$1.02	**$3.09**	$2.72

Net income attributable to common shares decreased by $189 million or $0.23 per common share for the three months ended September 30, 2019, and increased by $421 million or $0.37 per common share for the nine months ended September 30, 2019, compared to the same periods in 2018. Net income per common share reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Net income in both periods included unrealized gains and losses from changes in risk management activities which we excluded along with other specific items as noted below to arrive at comparable earnings.

2019 results included:

- an after-tax loss of $133 million at September 30, 2019 related to the Ontario natural gas-fired power plants held for sale. The total after-tax loss on this sale is expected to be $231 million. The remaining loss primarily reflects the residual costs to be incurred until Napanee is placed in service, including capitalized interest, and will be recorded on or before closing of the transaction, which is anticipated by the end of first quarter 2020
- an after-tax loss of $133 million related to the sale of certain Columbia Midstream assets in August 2019
- an after-tax gain of $115 million related to the partial sale of Northern Courier in July 2019
- an after-tax gain of $54 million related to the sale of our Coolidge generating station in May 2019
- a deferred tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to rate-regulated accounting in June 2019
- an after-tax loss of $6 million for the nine months ended September 30, 2019 related to the remainder of our U.S. Northeast power marketing contracts which were sold in May 2019.

Refer to the Recent developments section for additional information regarding the above noted dispositions.

2018 results included:

- after-tax income of $8 million and $3 million for the three and nine months ended September 30, 2018 related to our U.S. Northeast power marketing contracts.

These amounts have been excluded from comparable earnings as we do not consider these transactions or adjustments to be a part of our underlying operations.

A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Net income attributable to common shares	**739**	928	**2,868**	2,447
Specific items (net of tax):				
Loss on sale of Columbia Midstream assets	**133**	—	**133**	—
Loss on Ontario natural gas-fired power plants held for sale	**133**	—	**133**	—
Gain on partial sale of Northern Courier	**(115)**	—	**(115)**	—
Gain on sale of Coolidge generating station	**—**	—	**(54)**	—
Alberta corporate income tax rate reduction	**—**	—	**(32)**	—
U.S. Northeast power marketing contracts	**—**	(8)	**6**	(3)
Risk management activities[1]	**80**	(18)	**(58)**	90
Comparable earnings	**970**	902	**2,881**	2,534
Net income per common share	**$0.79**	$1.02	**$3.09**	$2.72
Specific items (net of tax):				
Loss on sale of Columbia Midstream assets	**0.14**	—	**0.14**	—
Loss on Ontario natural gas-fired power plants held for sale	**0.14**	—	**0.14**	—
Gain on partial sale of Northern Courier	**(0.12)**	—	**(0.12)**	—
Gain on sale of Coolidge generating station	**—**	—	**(0.06)**	—
Alberta corporate income tax rate reduction	**—**	—	**(0.03)**	—
U.S. Northeast power marketing contracts	**—**	(0.01)	**0.01**	—
Risk management activities	**0.09**	(0.01)	**(0.06)**	0.10
Comparable earnings per common share	**$1.04**	$1.00	**$3.11**	$2.82

1

Risk management activities	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Canadian Power	**(1)**	—	**(1)**	3
U.S. Power	**—**	31	**(52)**	(31)
Liquids marketing	**(70)**	(65)	**(36)**	(10)
Natural Gas Storage	**(3)**	—	**(8)**	(6)
Foreign exchange	**(31)**	60	**176**	(79)
Income tax attributable to risk management activities	**25**	(8)	**(21)**	33
Total unrealized (losses)/gains from risk management activities	**(80)**	18	**58**	(90)

COMPARABLE EBITDA TO COMPARABLE EARNINGS

Comparable EBITDA represents segmented earnings adjusted for the specific items described above and excludes non-cash charges for depreciation and amortization.

(millions of $, except per share amounts)	three months ended September 30 2019	three months ended September 30 2018	nine months ended September 30 2019	nine months ended September 30 2018
Comparable EBITDA				
Canadian Natural Gas Pipelines	**572**	522	**1,656**	1,561
U.S. Natural Gas Pipelines	**796**	715	**2,625**	2,223
Mexico Natural Gas Pipelines	**153**	153	**440**	455
Liquids Pipelines	**575**	467	**1,720**	1,311
Power and Storage	**252**	207	**622**	585
Corporate	**(4)**	(8)	**(12)**	(25)
Comparable EBITDA	**2,344**	2,056	**7,051**	6,110
Depreciation and amortization	**(610)**	(564)	**(1,839)**	(1,669)
Interest expense	**(573)**	(577)	**(1,747)**	(1,662)
Allowance for funds used during construction	**120**	147	**358**	365
Interest income and other included in comparable earnings	**49**	48	**85**	166
Income tax expense included in comparable earnings	**(260)**	(108)	**(687)**	(425)
Net income attributable to non-controlling interests	**(59)**	(59)	**(217)**	(229)
Preferred share dividends	**(41)**	(41)	**(123)**	(122)
Comparable earnings	**970**	902	**2,881**	2,534
Comparable earnings per common share	**$1.04**	$1.00	**$3.11**	$2.82

Comparable EBITDA – 2019 versus 2018

Comparable EBITDA increased by $288 million for the three months ended September 30, 2019 compared to the same period in 2018 primarily due to the net effect of the following:

- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities, partially offset by the sale of an 85 per cent equity interest in Northern Courier in July 2019
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by decreased earnings from Bison (wholly-owned by TC PipeLines, LP) and from the sale of certain Columbia Midstream assets in August 2019
- higher contribution from Canadian Natural Gas Pipelines mainly due to the Canadian Mainline recovery of increased depreciation and higher incentive earnings in 2019
- higher contribution from Power and Storage primarily due to increased Bruce Power results from a higher realized power price and higher output, partially offset by the sale of our interests in the Cartier Wind power facilities in fourth quarter 2018 and the sale of our Coolidge generating station in May 2019.

Comparable EBITDA increased by $941 million for the nine months ended September 30, 2019 compared to the same period in 2018 and was primarily due to the net effect of the following:

- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities, partially offset by decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by decreased earnings from Bison (wholly-owned by TC PipeLines, LP) and from the sale of certain Columbia Midstream assets in August 2019
- higher contribution from Canadian Natural Gas Pipelines mainly due to the Canadian Mainline recovery of increased depreciation and higher incentive earnings in 2019, partially offset by lower flow-through income taxes on the NGTL System as a result of accelerated tax depreciation
- higher contribution from Power and Storage primarily due to increased Bruce Power results from a higher realized power price net of lower generation due to increased outage days, partially offset by the sale of our interests in the Cartier Wind power facilities in 2018 and the sale of our Coolidge generating station in May 2019
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from our U.S. operations.

Due to the flow-through treatment of certain expenses including income taxes and depreciation on our Canadian rate-regulated pipelines, the accelerated tax depreciation changes in 2019 and increased depreciation expense impacts our comparable EBITDA despite having no effect on net income.

Comparable earnings – 2019 versus 2018

Comparable earnings increased by $68 million or $0.04 per common share for the three months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher income tax expense primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials
- higher depreciation, largely in Canadian Natural Gas Pipelines which is fully recovered in tolls as reflected in the comparable EBITDA discussion above, therefore having no impact on comparable earnings. In addition, higher consolidated depreciation reflects new projects placed in service
- lower AFUDC in U.S. Natural Gas Pipelines primarily due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by continued investment in our NGTL System expansion and Mexico projects.

Comparable earnings increased by $347 million or $0.29 per common share for the nine months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher income tax expense due to higher comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes on the NGTL System
- higher depreciation, largely in Canadian Natural Gas Pipelines which is fully recovered in tolls as reflected in the increase in comparable EBITDA described above therefore having no impact on comparable earnings. In addition, higher consolidated depreciation reflects new projects placed in service
- higher interest expense primarily as a result of higher levels of short-term borrowings, the foreign exchange impact on translation of U.S. dollar-denominated interest, and long-term debt issuances, net of maturities, partially offset by higher capitalized interest
- lower interest income and other due to realized losses in 2019 compared to realized gains in 2018 on derivatives used to manage exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable earnings per common share for the three and nine months ended September 30, 2019 also reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Capital Program

We are developing quality projects under our capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties or regulated business models and are expected to generate significant growth in earnings and cash flow.

Our capital program consists of approximately $30 billion of secured projects which include commercially supported, committed projects that are either under construction, are in or are preparing to commence the permitting stage but are not yet fully approved. An additional $21 billion of projects under development are commercially supported (except where noted) but have greater uncertainty with respect to timing and estimated project costs and are subject to certain approvals. In the nine months ended September 30, 2019, we have placed approximately $8.2 billion of projects in service including Mountaineer XPress, Gulf XPress, various NGTL System expansions and the Sur de Texas and White Spruce pipelines.

Three years of maintenance capital expenditures for our businesses are included in the secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipelines businesses are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in our liquids pipelines business provide for the recovery of maintenance capital expenditures.

All projects are subject to cost and timing adjustments due to weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, among other factors. Amounts presented in the following tables exclude capitalized interest and AFUDC.

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at September 30, 2019
Canadian Natural Gas Pipelines			
Canadian Mainline	2019-2022	0.4	0.1
NGTL System[2,3]	2019	2.5	2.4
	2020	2.1	0.8
	2021	2.6	0.1
	2022+	2.8	—
Coastal GasLink[4,5]	2023	6.6	0.8
Regulated maintenance capital expenditures	2019-2021	1.8	0.4
U.S. Natural Gas Pipelines			
Columbia Gas			
Modernization II	2019-2020	US 1.1	US 0.7
Other capacity capital	2019-2022	US 1.5	US 0.1
Regulated maintenance capital expenditures	2019-2021	US 2.1	US 0.4
Mexico Natural Gas Pipelines			
Villa de Reyes	2020	US 0.9	US 0.7
Tula[6]	—	US 0.8	US 0.6
Liquids Pipelines			
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2019-2021	0.1	—
Power and Storage			
Bruce Power – life extension[7]	2019-2023	2.2	0.9
Other			
Non-recoverable maintenance capital expenditures[8]	2019-2021	0.7	0.2
		28.3	**8.2**
Foreign exchange impact on secured projects[9]		**2.0**	**0.8**
Total secured projects (Cdn$)		**30.3**	**9.0**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.

2 The North Montney project is included in the 2019 program, although a portion of this project is expected to be placed into service in January 2020.

3 Includes $0.7 billion for the Foothills pipeline system related to the West Path Delivery Program.

4 Represents 100 per cent of required capital prior to potential joint venture partners or project financing.

5 Carrying value is net of the fourth quarter 2018 receipts from the LNG Canada participants for the reimbursement of approximately $0.5 billion of pre-FID costs pursuant to project agreements.

6 Construction of the central segment for the Tula project has been delayed due to a lack of progress to successfully complete Indigenous consultation by the Secretary of Energy. The east and west segments of Tula are being considered as part of the current renegotiation with CFE.

7 Reflects our proportionate share of the Unit 6 Major Component Replacement program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2023.

8 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Power and Storage assets.

9 Reflects U.S./Canada foreign exchange rate of 1.32 at September 30, 2019.

Projects under development

The costs provided in the table below reflect the most recent estimates for each project as filed with the various regulatory authorities or otherwise determined by management.

(billions of $)	Estimated project cost[1]	Carrying value at September 30, 2019
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
U.S. Natural Gas Pipelines		
Other capacity capital[2]	US 0.4	—
Liquids Pipelines		
Keystone XL[3]	US 8.0	US 1.0
Heartland and TC Terminals[4]	0.9	0.1
Grand Rapids Phase 2[4]	0.7	—
Keystone Hardisty Terminal[4]	0.3	0.1
Power and Storage		
Bruce Power – life extension[5]	6.0	—
	18.2	1.2
Foreign exchange impact on projects under development[6]	2.7	0.3
Total projects under development (Cdn$)	**20.9**	**1.5**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.

2 Includes projects subject to a positive customer FID.

3 Carrying value reflects amount remaining after impairment charge recorded in 2015 along with additional amounts capitalized from January 1, 2018. A portion of the carrying value is recoverable from shippers under certain conditions.

4 Regulatory approvals have been obtained and additional commercial support is being pursued.

5 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.

6 Reflects U.S./Canada foreign exchange rate of 1.32 at September 30, 2019.

Outlook

Consolidated comparable earnings

Our overall comparable earnings outlook for 2019 remains consistent with the 2018 Annual Report taking into consideration the net effect of:

- higher expected volumes on the Keystone Pipeline System as well as higher contribution from liquids marketing activities
- delays in the commencement of operations on the Napanee power plant and Sur de Texas pipeline
- uncertainty regarding the impact of final U.S. Tax Reform regulations, expected in late 2019, on the cost of financing certain of our U.S. operations
- asset sales and use of proceeds.

Consolidated capital spending

Our total capital expenditures for 2019 are expected to be approximately $9 billion on growth projects, maintenance capital expenditures and contributions to equity investments. The increase relative to the outlook in the 2018 Annual Report is primarily a result of higher spending on Napanee, the NGTL System and Mountaineer XPress as well as changes in foreign exchange rates.

Canadian Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
NGTL System	**311**	302	**871**	884
Canadian Mainline	**234**	195	**704**	592
Other Canadian pipelines[1]	**27**	25	**81**	85
Comparable EBITDA	**572**	522	**1,656**	1,561
Depreciation and amortization	**(289)**	(255)	**(862)**	(761)
Comparable EBIT and segmented earnings	**283**	267	**794**	800

1 Includes results from Foothills, Ventures LP, Great Lakes Canada and our share of equity income from our investment in TQM as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings increased by $16 million and decreased by $6 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

NET INCOME AND AVERAGE INVESTMENT BASE

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Net Income				
NGTL System	**124**	101	**355**	289
Canadian Mainline	**43**	40	**129**	121
Average investment base				
NGTL System			**11,654**	9,419
Canadian Mainline			**3,677**	3,855

Net income for the NGTL System increased by $23 million and $66 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2018-2019 Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed common equity, a mechanism for sharing variances above and below a fixed annual OM&A amount and flow-through treatment of all other costs.

Net income for the Canadian Mainline increased by $3 million and $8 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. The increase in the nine months ended September 30, 2019 is mainly due to higher incentive earnings. We did not record incentive earnings in the first nine months of 2018 pending the outcome of the Canadian Mainline 2018-2020 toll review. The NEB 2018 Decision, received in December 2018, preserved the incentive arrangement from the NEB 2014 Decision along with an approved ROE of 10.1 per cent on 40 per cent deemed equity. As a result, we recorded the 2018 full-year incentive earnings in fourth quarter 2018.

COMPARABLE EBITDA

Comparable EBITDA for the Canadian Natural Gas Pipelines increased by $50 million and $95 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 due to the net effect of:

- increased depreciation on the Canadian Mainline due to higher rates approved in the NEB 2018 Decision
- increased incentive earnings on the Canadian Mainline
- lower flow-through income taxes on the NGTL System and the Canadian Mainline as a result of the Canadian federal government's accelerated tax depreciation, enacted in June 2019, to allow businesses in Canada to deduct the cost of their investments more quickly. Due to the flow-through treatment of income taxes on our Canadian rate-regulated pipelines, this beneficial income tax change reduces our comparable EBITDA despite having no impact on net income
- increased rate base earnings on the NGTL System
- increased depreciation on the NGTL System due to additional facilities that were placed in service.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $34 million and $101 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to the increase in composite depreciation rates approved in the Mainline NEB 2018 Decision as well as additional NGTL System facilities that were placed in service.

U.S. Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of US$, unless otherwise noted)	**2019**	**2018**	**2019**	**2018**
Columbia Gas	**291**	204	**906**	637
ANR	**107**	111	**373**	370
TC PipeLines, LP[1,2]	**26**	30	**88**	102
Great Lakes[3]	**15**	18	**62**	74
Midstream	**18**	42	**87**	101
Columbia Gulf	**47**	34	**131**	90
Other U.S. pipelines[4]	**21**	19	**58**	50
Non-controlling interests[5]	**79**	89	**270**	304
Comparable EBITDA	**604**	547	**1,975**	1,728
Depreciation and amortization	**(145)**	(130)	**(425)**	(380)
Comparable EBIT	**459**	417	**1,550**	1,348
Foreign exchange impact	**146**	128	**510**	386
Comparable EBIT (Cdn$)	**605**	545	**2,060**	1,734
Specific item:				
Gain on sale of Columbia Midstream assets	**21**	—	**21**	—
Segmented earnings (Cdn$)	**626**	545	**2,081**	1,734

1 Reflects our earnings from TC PipeLines, LP's ownership interests in eight natural gas pipelines as well as general and administrative costs related to TC PipeLines, LP.
2 For the three and nine months ended September 30, 2019, our ownership interest in TC PipeLines, LP was 25.5 per cent which is unchanged from the same periods in 2018.
3 Reflects our 53.55 per cent direct interest in Great Lakes. The remaining 46.45 per cent is held by TC PipeLines, LP.
4 Reflects earnings from our effective ownership in Millennium and Hardy Storage as well as general and administrative and business development costs related to our U.S. natural gas pipelines.
5 Reflects earnings attributable to portions of TC PipeLines, LP that we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $81 million and $347 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and included a pre-tax gain of $21 million related to the sale of certain Columbia Midstream assets in August 2019 which has been excluded from comparable EBIT. Refer to the Recent developments section for further information.

In addition to the net increases in comparable EBITDA noted below, a stronger U.S. dollar in 2019 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same periods in 2018.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$57 million and US$247 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. This was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- decreased earnings from Bison (wholly-owned by TC PipeLines, LP) due to 2018 customer agreements to pay out their future contracted revenues and terminate their contracts
- decreased earnings as a result of the sale of certain Columbia Midstream assets in August 2019.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$15 million and US$45 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to new projects placed in service, partially offset by lower depreciation as a result of the Bison (wholly-owned by TC PipeLines, LP) asset impairment in 2018 and the sale of certain Columbia Midstream assets in August 2019.

Mexico Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of US$, unless otherwise noted)	**2019**	**2018**	**2019**	**2018**
Topolobampo	**40**	42	**120**	128
Tamazunchale	**31**	33	**93**	96
Mazatlán	**17**	19	**52**	58
Guadalajara	**17**	18	**49**	53
Sur de Texas[1]	**10**	4	**18**	14
Other	**—**	—	**—**	4
Comparable EBITDA	**115**	116	**332**	353
Depreciation and amortization	**(21)**	(19)	**(65)**	(56)
Comparable EBIT	**94**	97	**267**	297
Foreign exchange impact	**31**	30	**87**	85
Comparable EBIT and segmented earnings (Cdn$)	**125**	127	**354**	382

1 Represents equity income from our 60 per cent interest.

Mexico Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $2 million and $28 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. Lower EBITDA as described below was partially offset by a stronger U.S. dollar in 2019 which had a positive impact on the Canadian dollar equivalent earnings.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$1 million and US$21 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 mainly due to the net effect of:

- lower revenues from operations primarily as a result of changes in timing of revenue recognition in 2018
- higher equity earnings from our investment in the Sur de Texas pipeline which was placed in service on September 17, 2019, at which time recording of equity income from operations commenced. Prior to in-service, Sur de Texas equity income primarily reflected AFUDC during construction, net of interest expense on an inter-affiliate loan from TC Energy. This interest expense is fully offset in Interest income and other in the Corporate segment.

Following the execution of an amending agreement with CFE for the Sur de Texas pipeline and commencement of operations, revenue is being recognized for this pipeline at a levelized average rate over the now 35-year contract. Refer to the Recent developments section for additional information.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$2 million and US$9 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 reflecting new assets in service and other adjustments.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Keystone Pipeline System	**415**	350	**1,283**	1,042
Intra-Alberta pipelines	**29**	46	**109**	122
Liquids marketing and other	**131**	71	**328**	147
Comparable EBITDA	**575**	467	**1,720**	1,311
Depreciation and amortization	**(83)**	(86)	**(260)**	(254)
Comparable EBIT	**492**	381	**1,460**	1,057
Specific items:				
Gain on partial sale of Northern Courier	**69**	—	**69**	—
Risk management activities	**(70)**	(65)	**(36)**	(10)
Segmented earnings	**491**	316	**1,493**	1,047
Comparable EBIT denominated as follows:				
Canadian dollars	**88**	96	**272**	278
U.S. dollars	**306**	218	**894**	605
Foreign exchange impact	**98**	67	**294**	174
Comparable EBIT	**492**	381	**1,460**	1,057

Liquids Pipelines segmented earnings increased by $175 million and $446 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and included the following specific items which have been excluded from our calculation of comparable EBIT:

- a pre-tax gain of $69 million related to the sale of an 85 per cent equity interest in Northern Courier. Refer to the Recent developments section for additional information
- unrealized losses from changes in the fair value of derivatives related to our liquids marketing business.

Comparable EBITDA for Liquids Pipelines increased by $108 million and $409 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. This was primarily the net effect of:

- higher volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities due to improved margins and volumes
- contribution from the White Spruce pipeline, which went into service in May 2019
- decreased earnings as a result of the sale of an 85 per cent equity interest in Northern Courier in July 2019
- positive foreign exchange impact on the Canadian dollar equivalent earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $3 million and increased by $6 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. The decrease in the three-month period is primarily a result of the sale of an 85 per cent equity interest in Northern Courier. The increase for the nine-month period is the net result of new facilities being placed in service and the effect of a stronger U.S. dollar, partially offset by the sale of an 85 per cent equity interest in Northern Courier.

Power and Storage

As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Western and Eastern Power[1]	**61**	106	**228**	329
Bruce Power[1]	**193**	100	**378**	245
Natural Gas Storage and other	**2**	4	**25**	21
Business development	**(4)**	(3)	**(9)**	(10)
Comparable EBITDA	**252**	207	**622**	585
Depreciation and amortization	**(19)**	(27)	**(66)**	(92)
Comparable EBIT	**233**	180	**556**	493
Specific items:				
Loss on Ontario natural gas-fired power plants held for sale	**(202)**	—	**(202)**	—
Gain on sale of Coolidge generating station	**—**	—	**68**	—
U.S. Northeast power marketing contracts	**—**	12	**(8)**	5
Risk management activities	**(4)**	31	**(61)**	(34)
Segmented earnings	**27**	223	**353**	464

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.

Power and Storage segmented earnings decreased by $196 million and $111 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and included the following specific items which have been excluded from comparable EBIT:

- a pre-tax loss of $202 million recorded in third quarter 2019 related to the Ontario natural gas-fired power plants held for sale
- a pre-tax gain of $68 million related to the sale of our Coolidge generating station in May 2019
- pre-tax losses of nil and $8 million for the three and nine months ended September 30, 2019, (2018 – pre-tax gains of $12 million and $5 million, respectively) related to our U.S. Northeast power marketing contracts, the remainder of which were sold in May 2019
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Refer to the Recent developments section for additional information regarding the above noted dispositions.

Comparable EBITDA for Power and Storage increased by $45 million and $37 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to the net effect of:

- increased Bruce Power results mainly due to a higher realized power price and higher output due to fewer outage days for the three months ended September 30, 2019. Results increased for the nine months ended September 30, 2019 largely due to a higher realized power price, partially offset by lower volumes from greater outage days. Additional financial and operating information on Bruce Power is provided below
- decreased Western and Eastern Power results largely due to the sale of our interests in the Cartier Wind power facilities in October 2018, the sale of our Coolidge generating station in May 2019 and lower realized margins on lower generation volumes.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $8 million and $26 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to the cessation of depreciation on our Coolidge generating station at December 31, 2018 and our Halton Hills power plant at July 30, 2019 upon classification as held for sale as well as the sale of our interests in the Cartier Wind power facilities in October 2018.

BRUCE POWER

The following reflects our proportionate share of the components of comparable EBITDA and comparable EBIT.

	three months ended September 30		nine months ended September 30	
(millions of $, unless otherwise noted)	**2019**	**2018**	**2019**	**2018**
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues[1]	**499**	397	**1,284**	1,153
Operating expenses	**(217)**	(204)	**(660)**	(640)
Depreciation and other	**(89)**	(93)	**(246)**	(268)
Comparable EBITDA and EBIT[2]	**193**	100	**378**	245
Bruce Power – other information				
Plant availability[3]	**93%**	89%	**83%**	88%
Planned outage days	**45**	30	**291**	180
Unplanned outage days	**3**	43	**57**	77
Sales volumes (GWh)[2]	**6,321**	6,087	**16,817**	17,810
Realized power price per MWh[4]	**$78**	$67	**$75**	$67

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.4 per cent (2018 – 48.3 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Calculation based on actual and deemed generation. Realized power price per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Planned outage work on Units 3 and 7 was completed in the first half of 2019. Planned maintenance on Unit 5 began in August 2019 and is scheduled to be completed in fourth quarter 2019. Planned maintenance on Unit 2 is expected in fourth quarter 2019. The overall average plant availability percentage in 2019 is expected to be in the low-80 per cent range.

On April 1, 2019, Bruce Power's contract price increased from approximately $68 per MWh to a final adjusted contract price of approximately $78 per MWh including flow-through items, reflecting capital to be invested under the Unit 6 Major Component Replacement program and the Asset Management program as well as annual inflation adjustments.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings/(losses) (the most directly comparable GAAP measure).

	three months ended September 30		nine months ended September 30	
(millions of $)	2019	2018	2019	2018
Comparable EBITDA and EBIT	**(4)**	(8)	**(12)**	(25)
Specific item:				
Foreign exchange gain/(loss) – inter-affiliate loan[1]	**37**	(60)	**11**	(52)
Segmented earnings/(losses)	**33**	(68)	**(1)**	(77)

1 Reported in Income from equity investments in the Condensed consolidated statement of income.

Corporate segmented earnings increased by $101 million for the three months ended September 30, 2019 while Corporate segmented losses decreased by $76 million for the nine months ended September 30, 2019 compared to the same periods in 2018. Segmented earnings/(losses) include foreign exchange gains and losses on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing which are fully offset by corresponding foreign exchange losses and gains included in Interest income and other on the inter-affiliate loan receivable. These amounts have been excluded from our calculation of comparable EBIT.

Comparable EBITDA increased by $4 million and $13 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to U.S. capital tax adjustments recorded in second quarter 2018 and decreased general and administrative costs.

OTHER INCOME STATEMENT ITEMS

Interest expense

	three months ended September 30		nine months ended September 30	
(millions of $)	2019	2018	2019	2018
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(152)**	(142)	**(440)**	(407)
U.S. dollar-denominated	**(330)**	(335)	**(989)**	(981)
Foreign exchange impact	**(106)**	(103)	**(326)**	(283)
	(588)	(580)	**(1,755)**	(1,671)
Other interest and amortization expense	**(33)**	(30)	**(121)**	(80)
Capitalized interest	**48**	33	**129**	89
Interest expense	**(573)**	(577)	**(1,747)**	(1,662)

Interest expense decreased by $4 million and increased by $85 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to the net effect of:

- long-term debt issuances, net of maturities
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest
- higher levels of short-term borrowings
- higher capitalized interest primarily related to Keystone XL and Napanee.

Allowance for funds used during construction

(millions of $)	three months ended September 30 2019	2018	nine months ended September 30 2019	2018
Canadian dollar-denominated	**57**	27	**151**	68
U.S. dollar-denominated	**48**	91	**156**	230
Foreign exchange impact	**15**	29	**51**	67
Allowance for funds used during construction	**120**	147	**358**	365

AFUDC decreased by $27 million and $7 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. The increase in Canadian dollar-denominated AFUDC is primarily due to capital expenditures on our NGTL System expansion projects. The decrease in U.S. dollar-denominated AFUDC is largely due to Columbia Gas and Columbia Gulf growth projects placed in service, partially offset by continued investment in our Mexico projects.

Interest income and other

(millions of $)	three months ended September 30 2019	2018	nine months ended September 30 2019	2018
Interest income and other included in comparable earnings	**49**	48	**85**	166
Specific items:				
Foreign exchange (loss)/gain – inter-affiliate loan	**(37)**	60	**(11)**	52
Risk management activities	**(31)**	60	**176**	(79)
Interest income and other	**(19)**	168	**250**	139

Interest income and other decreased by $187 million for the three months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- foreign exchange losses in 2019 compared to foreign exchange gains in 2018 related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding foreign exchange gains and losses in Sur de Texas are reflected in Income from equity investments, resulting in no net impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- unrealized losses in 2019 compared to unrealized gains in 2018 from foreign exchange risk management activities. These amounts have been excluded from comparable earnings.

Interest income and other increased by $111 million for the nine months ended September 30, 2019 compared to the same period in 2018 and was primarily the net effect of:

- unrealized gains in 2019 compared to unrealized losses in 2018 from foreign exchange risk management activities. These amounts have been excluded from comparable earnings
- foreign exchange losses in 2019 compared to foreign exchange gains in 2018 related to a peso-denominated inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding foreign exchange gains and losses in Sur de Texas are reflected in Income from equity investments, resulting in no net impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- realized losses in 2019 compared to realized gains in 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income tax expense

(millions of $)	three months ended September 30 2019	2018	nine months ended September 30 2019	2018
Income tax expense included in comparable earnings	**(260)**	(108)	**(687)**	(425)
Specific items:				
Gain on partial sale of Northern Courier	**46**	—	**46**	—
Loss on sale of Columbia Midstream assets	**(154)**	—	**(154)**	—
Loss on Ontario natural gas-fired power plants held for sale	**69**	—	**69**	—
Gain on sale of Coolidge generating station	**—**	—	**(14)**	—
Alberta corporate income tax rate reduction	**—**	—	**32**	—
U.S. Northeast power marketing contracts	**—**	(4)	**2**	(2)
Risk management activities	**25**	(8)	**(21)**	33
Income tax expense	**(274)**	(120)	**(727)**	(394)

Income tax expense included in comparable earnings increased by $152 million and $262 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018. This was primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials, partially offset by lower flow-through income taxes in Canadian rate-regulated pipelines.

In second quarter 2019, we recorded a $32 million income tax recovery on deferred income tax balances attributable to our Canadian businesses not subject to rate-regulated accounting due to the Alberta corporate income tax rate reduction enacted in June 2019. This has been excluded from comparable earnings.

Refer to the Recent developments section for additional information on the income tax impacts of dispositions.

Net income attributable to non-controlling interests

(millions of $)	three months ended September 30 2019	2018	nine months ended September 30 2019	2018
Net income attributable to non-controlling interests	**(59)**	(59)	**(217)**	(229)

Net income attributable to non-controlling interests for the nine months ended September 30, 2019 decreased by $12 million compared to the same period in 2018 primarily due to lower earnings in TC PipeLines, LP, partially offset by the impact of a stronger U.S. dollar in 2019 on the Canadian dollar equivalent earnings.

Preferred share dividends

(millions of $)	three months ended September 30 2019	2018	nine months ended September 30 2019	2018
Preferred share dividends	**(41)**	(41)	**(123)**	(122)

Recent developments

CANADA ENERGY REGULATOR AND THE IMPACT ASSESSMENT AGENCY OF CANADA

On August 28, 2019, the Canadian Energy Regulator Act (CER Act) came into effect, replacing the National Energy Board Act (NEB Act), and the National Energy Board (NEB) was replaced by the Canada Energy Regulator (CER). The impact assessment and decision-making for designated major transboundary pipeline projects also changed with the implementation of the new Impact Assessment Act (IA Act) on August 28, 2019, which requires designated projects to be assessed by the Impact Assessment Agency of Canada, formerly the Canadian Environmental Assessment Agency. All TC Energy projects submitted to the NEB for review prior to August 28, 2019 will continue to be assessed under the previous NEB Act in accordance with the transitional rules under the CER Act.

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink Pipeline Project

Following the October 2018 positive FID by LNG Canada, construction activities continue along the pipeline route including the area south of Houston, B.C. which required a B.C. Supreme Court injunction for access. We expect a further decision in fourth quarter 2019 from the B.C. Supreme Court to extend the injunction to project completion.

On July 26, 2019, the NEB issued its decision affirming provincial jurisdiction for Coastal GasLink. Accordingly, construction will continue to proceed as planned under the permits granted to Coastal GasLink by the B.C. Oil and Gas Commission.

Our estimated project cost has increased from $6.2 billion to $6.6 billion due to increased scope and refinement of construction estimates for rock work and watercourse crossings. We expect the incremental cost will be incorporated into the final tolls.

TC Energy continues to advance funding plans for this pipeline project through a combination of the sale of up to 75 per cent ownership interest and arrangement of project financing, which are both proceeding as planned.

NGTL System

On October 31, 2019, we announced our West Path Delivery Program, an expansion of our NGTL System and Foothills pipeline system for incremental export capacity onto the GTN system in the Pacific Northwest. The Canadian portion of the expansion program has an estimated capital cost of $1.2 billion and consists of approximately 119 km (74 miles) of pipeline and associated facilities with in-service dates between fourth quarter 2022 and fourth quarter 2023. This Program is underpinned by approximately 275 TJ/d (258 MMcf/d) of new firm service contracts with terms that exceed 30 years.

On March 14, 2019, the NGTL System Rate Design and Services Application was filed with the NEB which included a settlement agreement negotiated with members of its Tolls, Tariff, Facilities and Procedures (TTFP) committee which represents stakeholders. The settlement is supported by the majority of members of the TTFP committee. The Application addresses rate design, terms and conditions of service for the NGTL System and a tolling methodology for the North Montney Mainline (NMML). Given the complexity of the issues raised in the Application, the NEB decided to hold a public hearing which is expected to conclude in fourth quarter 2019.

On May 16, 2019, the NEB approved the proposed NMML tolling methodology including the surcharge, as filed, on an interim basis, pending the outcome of the above Rate Design and Services Application.

In the nine months ended September 30, 2019, the NGTL System placed approximately $0.8 billion of capacity projects in service.

Canadian Mainline

In March 2019, the NEB approved Canadian Mainline tolls as filed in the January 2019 compliance filing related to the 2018-2020 Toll Review.

On May 9, 2019, we received NEB approval of the North Bay Junction Long Term Fixed Price service, as filed.

U.S. NATURAL GAS PIPELINES

Sale of Columbia Midstream Assets

On August 1, 2019, we finalized the sale of certain Columbia Midstream assets to UGI Energy Services, LLC, a subsidiary of UGI Corporation, for proceeds of approximately US$1.3 billion, before post-closing adjustments. The sale resulted in a pre-tax gain of $21 million ($133 million after-tax loss), which included the release of $595 million of Columbia's goodwill allocated to these assets that is not deductible for income tax purposes. This sale does not include any interest in Columbia Energy Ventures Company, which is our minerals business in the Appalachian basin.

Columbia Gulf Rate Settlement

Columbia Gulf and its shippers have recently agreed to a settlement-in-principle addressing all rate and service related issues raised during the settlement discussions. We plan to file an agreement with FERC before the end of the year reflecting this settlement-in-principle and precluding the need to file a general rate case as contemplated by Columbia Gulf's previous 2016 settlement. We anticipate that FERC will accept the settlement agreement and that it will be unopposed.

PHMSA Compliance Regulation

The Pipeline and Hazardous Materials Safety Administration (PHMSA) released its final rule revising the Federal Pipeline Safety Regulations. The rule updates reporting and records retention standards for gas transmission pipelines and expands the level of required integrity assessments that must be completed on certain pipeline segments outside of high consequence areas. The final rule also requires operators to review maximum allowable operating pressure records and perform specific remediation activities where records are not available. We are currently assessing the operational and financial impact related to this ruling which will become effective on July 1, 2020.

GTN XPress

In third quarter 2019, we initiated the GTN XPress project which is an integrated reliability and expansion project on the GTN system that will provide for the transport of additional volumes enabled by the West Path Delivery Program discussed above. GTN XPress is expected to be fully complete in late 2023 with an estimated total cost of US$0.3 billion.

East Lateral XPress

In second quarter 2019, we approved the East Lateral XPress project, an expansion project on the Columbia Gulf system that will connect supply to Gulf Coast LNG export markets. Subject to a positive customer FID, the anticipated in-service is 2022 with estimated project costs of US$0.3 billion.

Louisiana XPress and Grand Chenier XPress

Combined, the Louisiana XPress and Grand Chenier XPress projects will connect nearly 2 Bcf/d of supply to Gulf Coast LNG export facilities. Both projects have now obtained necessary customer approvals or waivers of conditions allowing the projects to move to the execution phase. Interim service for Louisiana XPress shippers will commence on Columbia Gulf November 1, 2019, with full in-service anticipated in 2022 and total estimated project costs of US$0.4 billion. The anticipated in-service dates for Grand Chenier XPress are in 2021 and 2022 for Phase I and II, respectively, with total estimated project costs of US$0.2 billion.

Mountaineer XPress and Gulf XPress

The Mountaineer XPress project, a Columbia Gas project transporting supply from the Marcellus and Utica shale plays to points along the system and the Leach interconnect with Columbia Gulf, was phased into service over first quarter 2019 along with Gulf XPress, a Columbia Gulf project.

MEXICO NATURAL GAS PIPELINES

CFE Arbitration

In June 2019, CFE filed requests for arbitration under the Sur de Texas, Villa de Reyes and Tula contracts. CFE requested nullification of clauses that govern the parties' responsibilities in instances of force majeure and requested reimbursement of certain fixed capacity payments. Regarding Sur de Texas, the parties successfully executed an amending agreement as described below and CFE has withdrawn its Sur de Texas arbitration request.

Negotiations continue with respect to the Villa de Reyes and Tula arbitrations with the expectation of reaching agreements before the end of 2019. Accordingly, these arbitration proceedings have been temporarily suspended while negotiations continue.

Sur de Texas

In September 2019, the Sur de Texas pipeline began commercial operations following execution of the above amending agreement with CFE. The original Sur de Texas agreement had a fluctuating toll profile over a 25-year contract term. As a result of the amendment, the contract has been extended and CFE will now receive transportation services for 35 years under a levelized toll structure based on actual construction costs with an initial fixed toll applicable for the first 25 years of the contract term and a higher fixed toll over the last 10 years of the contract. All other terms and conditions of the contract remain substantially unchanged. Monthly revenue for this pipeline will be recognized at a levelized average rate over the 35-year contract term.

Villa de Reyes

Construction of the Villa de Reyes project is ongoing, however the project has experienced force majeure events that have delayed the schedule. We anticipate a phased in-service to commence in early 2020 and have received certain capacity payments under force majeure provisions in the contract, but have not commenced recording revenues.

Tula

Construction on the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. The project in-service date is estimated to be two years after the Secretary of Energy successfully concludes such consultations. We have received certain capacity payments under force majeure provisions in the contract, but have not commenced recording revenues.

LIQUIDS PIPELINES

Keystone Pipeline System

In January 2019, we entered into an agreement with Motiva Enterprises LLC (Motiva) to construct a pipeline connection between the Keystone Pipeline system and Motiva's 630,000 Bbl/d refinery in Port Arthur, Texas. The connection is targeted to be operational in second quarter 2020.

In early February 2019, the Keystone Pipeline system was temporarily shut down after a leak was detected near St. Charles, Missouri. The pipeline system was restarted the same day while the segment between Steele City, Nebraska to Patoka, Illinois was restarted in mid-February 2019. This shutdown is not expected to have a significant impact on our 2019 earnings.

Keystone XL

In March 2019, U.S. President Trump issued a new Presidential Permit for the Keystone XL project which superseded the 2017 Permit and resulted in the dismissal of the cases related to the 2017 Permit and injunction barring certain pre-construction activities and construction of the project by the U.S. Court of Appeals (Appellate Court) for the Ninth Circuit.

On June 27, 2019, the U.S. Government and TC Energy filed motions to dismiss the lawsuit brought by two U.S. Native American communities that have been expanded to challenge both the 2017 and 2019 Presidential Permits. The U.S. District Court in Montana heard argument on motions to dismiss the complaints on September 12, 2019 and a decision is expected by year end.

On June 27, 2019, the U.S. Government filed a motion to dismiss the challenge to the 2019 Presidential Permit brought by the Indigenous Environmental Network. TC Energy has intervened and moved to dismiss this lawsuit. A hearing on the motion to dismiss and a motion for a preliminary injunction by the Indigenous Environmental Network was held by the U.S. District Court in Montana on October 9, 2019. A ruling is expected to be made by year end.

On August 23, 2019, the Nebraska Supreme Court affirmed the November 2017 decision by the Nebraska Public Service Commission that approved the Keystone XL Pipeline route through the state. A motion for re-hearing of the decision has been denied.

The U.S. Department of State issued a Draft Supplemental Environmental Impact Statement (DSEIS) for the project on October 4, 2019. The DSEIS supplements the 2014 Keystone XL SEIS. It considers changes in the project since 2014 including routing in Nebraska and incorporates updated information and new studies. The SEIS is expected to be issued by the end of 2019.

We continue to actively manage legal and regulatory matters as the project advances.

White Spruce

The White Spruce pipeline, which transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline, was placed in service in May 2019.

Northern Courier

On July 17, 2019, we completed the sale of an 85 per cent equity interest in Northern Courier to Alberta Investment Management Corporation for gross proceeds of $144 million before post-closing adjustments, resulting in a pre-tax gain of $69 million after recording our remaining 15 per cent interest at fair value. On an after-tax basis, the gain of $115 million reflects the utilization of previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds from which were paid to TC Energy, resulting in aggregate gross proceeds to TC Energy of $1.15 billion from this asset monetization.

We remain the operator of the Northern Courier pipeline and are using the equity method to account for our remaining 15 per cent interest in our Consolidated financial statements.

POWER AND STORAGE (PREVIOUSLY ENERGY)

Ontario natural gas-fired power plants

On July 30, 2019, we entered into an agreement to sell our Halton Hills and Napanee power plants as well as our 50 per cent interest in Portlands Energy Centre to a subsidiary of Ontario Power Generation Inc. for proceeds of approximately $2.87 billion, subject to timing of the close and related adjustments. The sale is expected to close by the end of first quarter 2020 subject to conditions which include regulatory approvals and Napanee reaching commercial operations as outlined in the agreement. We expect this sale to result in a total pre-tax loss of approximately $330 million ($231 million after tax). As these assets have been classified as held for sale, $202 million of this pre-tax loss ($133 million after tax) has been recorded at September 30, 2019. The remaining loss primarily reflects the residual costs to be incurred until Napanee is placed in service, including capitalized interest, and will be recorded on or before closing of the transaction.

In March 2019, Napanee experienced an equipment failure while progressing commissioning activities. Steps are being taken to address the situation and commercial operations are expected to commence in late first quarter 2020 with an estimated project cost of $1.8 billion.

Coolidge Generating Station

In December 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal (ROFR) on a sale to a third party and we terminated the agreement with SWG. On May 21, 2019, we completed the sale to SRP as per the terms of their ROFR for proceeds of US$448 million before post-closing adjustments, resulting in a pre-tax gain of $68 million ($54 million after tax).

Monetization of U.S. Northeast power business

In May 2019, we sold our remaining U.S. Northeast power marketing contracts. This transaction concludes the wind-down of our U.S. Northeast power marketing business.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management to meet our financing needs, manage our capital structure and to preserve our credit ratings.

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow from operations, access to capital markets, portfolio management, cash on hand, substantial committed credit facilities and, if deemed appropriate, our DRP. Annually, in fourth quarter, we renew and extend our credit facilities as required.

At September 30, 2019, our current assets totaled $8.3 billion and current liabilities amounted to $11.0 billion, leaving us with a working capital deficit of $2.7 billion compared to $7.8 billion at December 31, 2018. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flow from operations
- approximately $11.5 billion of unutilized, unsecured credit facilities
- our access to capital markets.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $, except per share amounts)	**2019**	**2018**	**2019**	**2018**
Net cash provided by operations	**1,585**	1,299	**5,256**	4,516
(Decrease)/increase in operating working capital	**(140)**	284	**(329)**	130
Funds generated from operations	**1,445**	1,583	**4,927**	4,646
Specific items:				
Current income tax expense on sale of Columbia Midstream assets	**357**	—	**357**	—
U.S. Northeast power marketing contracts	**—**	(12)	**8**	(5)
Comparable funds generated from operations	**1,802**	1,571	**5,292**	4,641
Dividends on preferred shares	**(40)**	(40)	**(120)**	(118)
Distributions to non-controlling interests	**(50)**	(57)	**(164)**	(174)
Non-recoverable maintenance capital expenditures[1]	**(55)**	(61)	**(178)**	(191)
Comparable distributable cash flow	**1,657**	1,413	**4,830**	4,158
Comparable distributable cash flow per common share	**$1.78**	$1.56	**$5.21**	$4.63

1 Includes non-recoverable maintenance capital expenditures from all segments including cash contributions to fund our proportionate share of maintenance capital expenditures for our equity investments which are primarily related to contributions to Bruce Power.

COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations by excluding the timing effects of working capital changes as well as the cash impact of our specific items.

Comparable funds generated from operations increased by $231 million and $651 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to higher comparable earnings adjusted for non-cash items and the cash impact of specific items.

NET CASH PROVIDED BY OPERATIONS

Net cash provided by operations increased by $286 million and $740 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 primarily due to higher funds generated from operations as well as the amount and timing of working capital changes.

COMPARABLE DISTRIBUTABLE CASH FLOW

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation.

Comparable distributable cash flow increased by $244 million and $672 million for the three and nine months ended September 30, 2019 compared to the same periods in 2018 and reflects higher comparable funds generated from operations as described above. Comparable distributable cash flow per common share of $1.78 and $5.21 for the three and nine months ended September 30, 2019 also incorporates the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

CASH USED IN INVESTING ACTIVITIES

	three months ended September 30		**nine months ended September 30**	
(millions of $)	**2019**	**2018**	**2019**	**2018**
Capital spending				
Capital expenditures	**(1,818)**	(2,435)	**(5,411)**	(6,474)
Capital projects in development	**(184)**	(127)	**(565)**	(239)
Contributions to equity investments	**(133)**	(236)	**(453)**	(778)
	(2,135)	(2,798)	**(6,429)**	(7,491)
Proceeds from sale of assets, net of transaction costs	**1,807**	—	**2,398**	—
Other distributions from equity investments	**—**	—	**186**	121
Deferred amounts and other	**(73)**	(16)	**(154)**	78
Net cash used in investing activities	**(401)**	(2,814)	**(3,999)**	(7,292)

Capital expenditures in 2019 were incurred primarily for the expansion of the NGTL System and Columbia Gas projects along with construction of the Coastal GasLink pipeline, Napanee power generating facility and maintenance capital expenditures. Lower spending in 2019 reflects Columbia Gas and Columbia Gulf growth projects being completed and placed in service and the approaching completion of Napanee, partially offset by increased spending on the NGTL System and Coastal GasLink.

Costs incurred on capital projects in development in 2019 and 2018 were mostly attributable to spending on Keystone XL.

Contributions to equity investments decreased in 2019 compared to 2018 mainly due to lower contributions to Sur de Texas, which included our proportionate share of debt financing requirements during construction, and lower contributions to Millennium.

In third quarter 2019, we closed the sale of certain of our Columbia Midstream assets for net proceeds of $1.7 billion (US$1.3 billion) and the sale of an 85 per cent equity interest in Northern Courier for net proceeds of $146 million.

In second quarter 2019, we closed the sale of our Coolidge generating station for net proceeds of $591 million.

Other distributions from equity investments reflect our proportionate share of Bruce Power and Northern Border financings undertaken to fund their respective capital programs and to make distributions to their partners. In first quarter 2019, we received distributions of $120 million (2018 – $121 million) from Bruce Power in connection with their issuance of senior notes in capital markets. In second quarter 2019, we received distributions of $66 million (2018 – nil) from Northern Border originating from a draw on its revolving credit facility to manage capitalization levels.

CASH PROVIDED BY FINANCING ACTIVITIES

	three months ended September 30		nine months ended September 30	
(millions of $)	**2019**	2018	**2019**	2018
Notes payable (repaid)/issued, net	**(2,584)**	1,421	**(688)**	1,906
Long-term debt issued, net of issue costs[1]	**1,994**	1,026	**3,015**	4,359
Long-term debt repaid[1]	**(1)**	(1,232)	**(1,835)**	(3,266)
Junior subordinated notes issued, net of issue costs	**1,441**	—	**1,441**	—
Dividends and distributions paid	**(549)**	(513)	**(1,628)**	(1,446)
Common shares issued, net of issue costs	**83**	354	**242**	1,139
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	—	**—**	49
Net cash provided by financing activities	**384**	1,056	**547**	2,741

1 Includes draws and repayments on an unsecured loan facility by TC PipeLines, LP.

We maintain access to debt capital markets to partially fund our growth programs and for other financing requirements. In July 2019, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds of which were paid to TC Energy prior to the sale of an 85 per cent equity interest in the pipeline. Refer to the Recent developments section for additional information.

In September 2019, we issued $1.0 billion of Medium Term Notes. As well, we issued US$1.1 billion of Junior Subordinated Notes through the TransCanada Trust, a wholly-owned financing trust subsidiary of TCPL. Further details related to our long-term debt and junior subordinated notes as at and for the three and nine months ended September 30, 2019 are discussed in Note 8, Long-term debt, and Note 9, Junior subordinated notes of our Condensed consolidated financial statements.

DIVIDEND REINVESTMENT PLAN

With respect to the common share dividend declared on August 1, 2019, the DRP participation rate amongst common shareholders was approximately 35 per cent resulting in $247 million reinvested in common equity under the program. Year-to-date in 2019, the participation rate amongst common shareholders has been approximately 34 per cent resulting in $711 million of dividends reinvested.

Commencing with the dividends declared October 31, 2019, common shares purchased with reinvested cash dividends under TC Energy's DRP will no longer be satisfied with shares issued from treasury at a discount, but rather will be acquired on the open market at 100 per cent of the weighted average purchase price. The DRP is available for dividends payable on TC Energy's common and preferred shares.

DIVIDENDS

On October 31, 2019, we declared quarterly dividends on our common shares of $0.75 per share payable on January 31, 2020 to shareholders of record at the close of business on December 31, 2019.

SHARE INFORMATION

At October 29, 2019, we had 934 million issued and outstanding common shares and 9 million outstanding options to buy common shares, of which 5 million were exercisable.

Shareholders of the Series 9 preferred shares had the option to convert to Series 10 preferred shares by providing notice on or before October 15, 2019. As the total number of Series 9 preferred shares tendered for conversion did not meet the established threshold, no Series 9 preferred shares were subsequently converted into Series 10 preferred shares.

CREDIT FACILITIES

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. In addition, we have demand credit facilities that are also used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At October 29, 2019, we had a total of $12.6 billion of committed revolving and demand credit facilities of which $11.4 billion remains available.

At October 29, 2019, our operated affiliates had an additional $0.8 billion of undrawn capacity on committed credit facilities.

Refer to Financial risks and financial instruments for more information about liquidity, market and other risks.

CONTRACTUAL OBLIGATIONS

Our capital expenditure commitments have remained at approximately the same level as on December 31, 2018. Increased commitments related to the construction of Coastal GasLink and Columbia growth projects were offset by the fulfillment of commitments for the NGTL System, White Spruce, Canadian Mainline and Villa de Reyes.

There were no other material changes to our contractual obligations in third quarter 2019 or to payments due in the next five years or after. Refer to the MD&A in our 2018 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to market risk and counterparty credit risk and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flow and, ultimately, shareholder value. Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

Refer to our 2018 Annual Report for more information about the risks we face in our business which have not changed substantially since December 31, 2018.

In May 2019, we sold our remaining U.S. Northeast power marketing contracts. This transaction concludes the wind-down of our U.S. Northeast power marketing business, reducing our commodity price risk.

INTEREST RATE RISK

We utilize short-term and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on our commercial paper programs and amounts drawn on our credit facilities and receive floating rates on cash and cash equivalents held. A small portion of our long-term debt is at floating interest rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We manage our interest rate risk using a combination of interest rate swaps and option derivatives.

FOREIGN EXCHANGE RISK

We generate revenues and incur expenses that are denominated in currencies other than Canadian dollars. As a result, our earnings and cash flows are exposed to currency fluctuations.

A portion of our businesses generate earnings in U.S. dollars, but since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is actively managed on a rolling one-year basis using foreign exchange derivatives, however, the natural exposure beyond that period remains.

Average exchange rate – U.S. to Canadian dollars

The average exchange rate for one U.S. dollar converted into Canadian dollars was as follows:

three months ended September 30, 2019	**1.32**
three months ended September 30, 2018	1.31
nine months ended September 30, 2019	**1.33**
nine months ended September 30, 2018	1.29

The impact of changes in the value of the U.S. dollar on our U.S. and Mexico operations is partially offset by interest on U.S. dollar-denominated debt as set out in the table below. Comparable EBIT is a non-GAAP measure.

Significant U.S. dollar-denominated amounts

(millions of US$)	three months ended September 30 2019	2018	nine months ended September 30 2019	2018
U.S. Natural Gas Pipelines comparable EBIT	**459**	417	**1,550**	1,348
Mexico Natural Gas Pipelines comparable EBIT[1]	**122**	122	**349**	366
U.S. Liquids Pipelines comparable EBIT	**306**	218	**894**	605
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(330)**	(335)	**(989)**	(981)
Capitalized interest on U.S. dollar-denominated capital expenditures	**9**	4	**24**	10
U.S. dollar-denominated allowance for funds used during construction	**48**	91	**156**	230
U.S. dollar comparable non-controlling interests and other	**(46)**	(50)	**(174)**	(195)
	568	467	**1,810**	1,383

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is offset in Interest income and other.

Net investment hedges

We hedge a portion of our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange options.

COUNTERPARTY CREDIT RISK

We have exposure to counterparty credit risk in the following areas:

- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- the fair value of derivative assets
- a loan receivable.

We monitor counterparties and review our accounts receivable regularly and, if needed, we record allowances for doubtful accounts using the specific identification method. At September 30, 2019, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

Continued low natural gas prices have presented increased financial challenges to certain of our WCSB and Appalachian natural gas pipeline shippers. We do not expect these shipper challenges to result in any material negative impact to our earnings or cash flow.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash flow and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

LOAN RECEIVABLE FROM AFFILIATE

We hold a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. We account for our interest in the joint venture as an equity investment. In 2017, we entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022.

At September 30, 2019, our Condensed consolidated balance sheet included a MXN$20.9 billion or $1.4 billion (December 31, 2018 – MXN$18.9 billion or $1.3 billion) loan receivable from the Sur de Texas joint venture which represents our proportionate share of long-term debt financing requirements related to the joint venture. Interest income and other included interest income of $38 million and $110 million for the three and nine months ended September 30, 2019 (2018 – $32 million and $88 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments in our Mexico Natural Gas Pipelines segment. As a result, there is no impact to net income.

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk and are classified as held for trading. Changes in the fair value of held-for-trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held-for-trading derivative instruments can fluctuate significantly from period to period.

Balance sheet presentation of derivative instruments

The balance sheet presentation of the fair value of derivative instruments is as follows:

(millions of $)	September 30, 2019	December 31, 2018
Other current assets	**211**	737
Intangible and other assets	**52**	61
Accounts payable and other	**(213)**	(922)
Other long-term liabilities	**(154)**	(42)
	(104)	(166)

Unrealized and realized (losses)/gains on derivative instruments

The following summary does not include hedges of our net investment in foreign operations:

(millions of $)	three months ended September 30		nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Derivative instruments held for trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities[2]	**(69)**	(31)	**(98)**	(41)
Foreign exchange	**(31)**	60	**176**	(79)
Amount of realized gains/(losses) in the period				
Commodities	**132**	81	**319**	210
Foreign exchange	**(9)**	(5)	**(68)**	14
Derivative instruments in hedging relationships				
Amount of realized gains/(losses) in the period				
Commodities	**1**	1	**(8)**	—
Interest rate	**1**	(2)	**1**	(1)

1 Realized and unrealized gains and losses on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held-for-trading derivative instruments are included on a net basis in Interest expense and Interest income and other, respectively.

2 In the three and nine months ended September 30, 2019 and 2018, there were no gains or losses included in Net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Effect of fair value and cash flow hedging relationships

The following tables detail amounts presented in the Condensed consolidated statement of income and in which accounts the effects of fair value or cash flow hedging relationships are recorded:

(millions of $)	three months ended September 30			
	Revenues (Power and Storage)		Interest Expense	
	2019	**2018**	**2019**	**2018**
Total Amount Presented in the Condensed Consolidated Statement of Income	**96**	535	**(573)**	(577)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(5)**	(17)
Derivatives designated as hedging instruments	**—**	—	**1**	(2)
Cash Flow Hedges				
Reclassification of losses on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**(1)**	(5)
Commodity contracts	**(4)**	(3)	**—**	—

1 Refer to our Condensed consolidated financial statements for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

	nine months ended September 30			
	Revenues (Power and Storage)		Interest Expense	
(millions of $)	2019	2018	2019	2018
Total Amount Presented in the Condensed Consolidated Statement of Income	**674**	1,724	**(1,747)**	(1,662)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(16)**	(59)
Derivatives designated as hedging instruments	**—**	—	**—**	(4)
Cash Flow Hedges				
Reclassification of losses on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**(9)**	(17)
Commodity contracts	**(4)**	(4)	**—**	—

1 Refer to our Condensed consolidated financial statements for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

Credit-risk-related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit-risk-related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at September 30, 2019, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $5 million (December 31, 2018 – $6 million), with no collateral provided in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2019, we would have been required to provide collateral of $5 million (December 31, 2018 – $6 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at September 30, 2019, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in third quarter 2019 that had or are likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. A summary of our critical accounting estimates is included in our 2018 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2018 other than described below. A summary of our significant accounting policies is included in our 2018 Annual Report.

Changes in accounting policies for 2019

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statement of income. The new guidance does not make extensive changes to lessor accounting.

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption (January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This transition option allowed us to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

We elected available practical expedients and exemptions upon adoption which allowed us:

- to not reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard
- to carry forward the historical lease classification and our accounting treatment for land easements on existing agreements
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption
- to not separate lease and non-lease components for all leases for which we are the lessee and for facility and liquids tank terminals for which we are the lessor
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

The new guidance had a significant impact on our Condensed consolidated balance sheet, but did not have an impact on our Condensed consolidated statements of income and cash flows. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases and providing significant new disclosures about our leasing activities. Refer to our Condensed consolidated financial statements for further information related to the impact of adopting the new guidance and our updated accounting policies related to leases.

In the application of the new guidance, significant assumptions and judgments are used to determine the following:

- whether a contract contains a lease
- the duration of the lease term including exercising lease renewal options. The lease term for all of our leases includes the noncancellable period of the lease plus any additional periods covered by either our option to extend (or not to terminate) the lease that we are reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor
- the discount rate for the lease.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. We elected to adopt this guidance effective first quarter 2019. The guidance was applied retrospectively and did not have a material impact on our consolidated financial statements.

Future accounting changes

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments, basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write-down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. We have substantially completed our analysis and do not expect the adoption of this new guidance to have a material impact on our consolidated financial statements.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We have substantially completed our analysis and do not expect the adoption of this new guidance to have a material impact on our consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020 and will be applied on a retrospective basis, however, early adoption is permitted. We do not expect the adoption of this new guidance to have a material impact on our consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit pension and other post-retirement benefit plans. This new guidance is effective January 1, 2021 and will be applied on a retrospective basis, however, early adoption is permitted. We are currently evaluating the timing and impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2019			2018				2017
(millions of $, except per share amounts)	Third	Second	First	Fourth	Third	Second	First	Fourth
Revenues	**3,133**	3,372	3,487	3,904	3,156	3,195	3,424	3,617
Net income attributable to common shares	**739**	1,125	1,004	1,092	928	785	734	861
Comparable earnings	**970**	924	987	946	902	768	864	719
Share statistics								
Net income per common share – basic and diluted	**$0.79**	$1.21	$1.09	$1.19	$1.02	$0.88	$0.83	$0.98
Comparable earnings per common share	**$1.04**	$1.00	$1.07	$1.03	$1.00	$0.86	$0.98	$0.82
Dividends declared per common share	**$0.75**	$0.75	$0.75	$0.69	$0.69	$0.69	$0.69	$0.625

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- newly constructed assets being placed in service
- acquisitions and divestitures
- developments outside of the normal course of operations.

In Liquids Pipelines, annual revenues and net income are based on contracted and uncommitted spot transportation and liquids marketing activities. Quarter-over-quarter revenues and net income are affected by:

- regulatory decisions
- newly constructed assets being placed in service
- acquisitions and divestitures
- demand for uncontracted transportation services
- liquids marketing activities
- developments outside of the normal course of operations
- certain fair value adjustments.

In Power and Storage, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- newly constructed assets being placed in service
- acquisitions and divestitures
- market prices for natural gas and power
- capacity prices and payments
- planned and unplanned plant outages
- developments outside of the normal course of operations
- certain fair value adjustments.

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

In third quarter 2019, comparable earnings also excluded:

- an after-tax loss of $133 million at September 30, 2019 related to the Ontario natural gas-fired power plants held for sale. The total after-tax loss on this sale is expected to be $231 million. The remaining loss primarily reflects the residual costs to be incurred until Napanee is placed in service, including capitalized interest, and will be recorded on or before closing which is anticipated by the end of first quarter 2020
- an after-tax loss of $133 million related to the sale of certain Columbia Midstream assets in August 2019
- an after-tax gain of $115 million related to the partial sale of Northern Courier in July 2019.

In second quarter 2019, comparable earnings also excluded:

- an after-tax gain of $54 million related to the sale of our Coolidge generating station
- a deferred tax benefit of $32 million related to the impact of an Alberta corporate income tax rate reduction on our Canadian businesses not subject to rate-regulated accounting
- an after-tax gain of $6 million related to the remainder of our U.S. Northeast power marketing contracts which were sold in May 2019.

In first quarter 2019, comparable earnings also excluded:

- an after-tax loss of $12 million related to our U.S. Northeast power marketing contracts.

In fourth quarter 2018, comparable earnings also excluded:

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

In third quarter 2018, comparable earnings also excluded:

- after-tax gain of $8 million related to our U.S. Northeast power marketing contracts.

In second quarter 2018, comparable earnings also excluded:

- an after-tax loss of $11 million related to our U.S. Northeast power marketing contracts.

In the first quarter 2018, comparable earnings also excluded:

- after-tax gain of $6 million related to our U.S. Northeast power marketing contracts, primarily due to income recognized on the sale of our retail contracts.

In fourth quarter 2017, comparable earnings also excluded:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended September 30 2019	three months ended September 30 2018	nine months ended September 30 2019	nine months ended September 30 2018
Revenues				
Canadian Natural Gas Pipelines	**1,016**	934	**2,939**	2,772
U.S. Natural Gas Pipelines	**1,176**	967	**3,691**	2,988
Mexico Natural Gas Pipelines	**151**	156	**455**	460
Liquids Pipelines	**694**	564	**2,233**	1,831
Power and Storage	**96**	535	**674**	1,724
	3,133	3,156	**9,992**	9,775
Income from Equity Investments	**334**	147	**695**	492
Operating and Other Expenses				
Plant operating costs and other	**980**	884	**2,816**	2,580
Commodity purchases resold	**2**	318	**368**	1,239
Property taxes	**178**	127	**546**	429
Depreciation and amortization	**610**	564	**1,839**	1,669
	1,770	1,893	**5,569**	5,917
Gain/(Loss) on Assets Held for Sale/Sold	**(112)**	—	**(44)**	—
Financial Charges				
Interest expense	**573**	577	**1,747**	1,662
Allowance for funds used during construction	**(120)**	(147)	**(358)**	(365)
Interest income and other	**19**	(168)	**(250)**	(139)
	472	262	**1,139**	1,158
Income before Income Taxes	**1,113**	1,148	**3,935**	3,192
Income Tax Expense				
Current	**452**	30	**724**	169
Deferred	**(178)**	90	**3**	225
	274	120	**727**	394
Net Income	**839**	1,028	**3,208**	2,798
Net income attributable to non-controlling interests	**59**	59	**217**	229
Net Income Attributable to Controlling Interests	**780**	969	**2,991**	2,569
Preferred share dividends	**41**	41	**123**	122
Net Income Attributable to Common Shares	**739**	928	**2,868**	2,447
Net Income per Common Share				
Basic and diluted	**$0.79**	$1.02	**$3.09**	$2.72
Weighted Average Number of Common Shares (millions)				
Basic	**932**	906	**927**	898
Diluted	**933**	907	**928**	898

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2019**	**2018**	**2019**	**2018**
Net Income	**839**	1,028	**3,208**	2,798
Other Comprehensive Income/(Loss), Net of Income Taxes				
Foreign currency translation gains and losses on net investment in foreign operations	**225**	(282)	**(530)**	409
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**(4)**	—	**(13)**	—
Change in fair value of net investment hedges	**(9)**	9	**24**	(6)
Change in fair value of cash flow hedges	**(26)**	4	**(85)**	9
Reclassification to net income of gains and losses on cash flow hedges	**4**	6	**10**	16
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**3**	10	**8**	10
Other comprehensive income on equity investments	**3**	6	**7**	18
Other comprehensive income/(loss)	**196**	(247)	**(579)**	456
Comprehensive Income	**1,035**	781	**2,629**	3,254
Comprehensive income attributable to non-controlling interests	**74**	28	**151**	304
Comprehensive Income Attributable to Controlling Interests	**961**	753	**2,478**	2,950
Preferred share dividends	**41**	41	**123**	122
Comprehensive Income Attributable to Common Shares	**920**	712	**2,355**	2,828

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended September 30 2019	three months ended September 30 2018	nine months ended September 30 2019	nine months ended September 30 2018
Cash Generated from Operations				
Net income	**839**	1,028	**3,208**	2,798
Depreciation and amortization	**610**	564	**1,839**	1,669
Deferred income taxes	**(178)**	90	**3**	225
Income from equity investments	**(334)**	(147)	**(695)**	(492)
Distributions received from operating activities of equity investments	**339**	296	**888**	761
Employee post-retirement benefits funding, net of expense	**3**	(22)	**(27)**	(22)
Loss/(gain) on assets held for sale/sold	**112**	—	**44**	—
Equity allowance for funds used during construction	**(76)**	(104)	**(225)**	(261)
Unrealized losses/(gains) on financial instruments	**100**	(29)	**(78)**	120
Other	**30**	(93)	**(30)**	(152)
Decrease/(increase) in operating working capital	**140**	(284)	**329**	(130)
Net cash provided by operations	**1,585**	1,299	**5,256**	4,516
Investing Activities				
Capital expenditures	**(1,818)**	(2,435)	**(5,411)**	(6,474)
Capital projects in development	**(184)**	(127)	**(565)**	(239)
Contributions to equity investments	**(133)**	(236)	**(453)**	(778)
Proceeds from sale of assets, net of transaction costs	**1,807**	—	**2,398**	—
Other distributions from equity investments	**—**	—	**186**	121
Deferred amounts and other	**(73)**	(16)	**(154)**	78
Net cash used in investing activities	**(401)**	(2,814)	**(3,999)**	(7,292)
Financing Activities				
Notes payable (repaid)/issued, net	**(2,584)**	1,421	**(688)**	1,906
Long-term debt issued, net of issue costs	**1,994**	1,026	**3,015**	4,359
Long-term debt repaid	**(1)**	(1,232)	**(1,835)**	(3,266)
Junior subordinated notes issued, net of issue costs	**1,441**	—	**1,441**	—
Dividends on common shares	**(459)**	(416)	**(1,344)**	(1,154)
Dividends on preferred shares	**(40)**	(40)	**(120)**	(118)
Distributions to non-controlling interests	**(50)**	(57)	**(164)**	(174)
Common shares issued, net of issue costs	**83**	354	**242**	1,139
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	—	**—**	49
Net cash provided by financing activities	**384**	1,056	**547**	2,741
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**15**	(10)	**(1)**	47
Increase/(Decrease) in Cash and Cash Equivalents	**1,583**	(469)	**1,803**	12
Cash and Cash Equivalents				
Beginning of period	**666**	1,570	**446**	1,089
Cash and Cash Equivalents				
End of period	**2,249**	1,101	**2,249**	1,101

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		September 30, 2019	December 31, 2018
ASSETS			
Current Assets			
Cash and cash equivalents		**2,249**	446
Accounts receivable		**1,957**	2,535
Inventories		**469**	431
Assets held for sale		**2,805**	543
Other		**794**	1,180
		8,274	5,135
Plant, Property and Equipment	net of accumulated depreciation of $26,960 and $25,834, respectively	**64,962**	66,503
Equity Investments		**6,617**	7,113
Regulatory Assets		**1,525**	1,548
Goodwill		**13,165**	14,178
Loan Receivable from Affiliate		**1,401**	1,315
Intangible and Other Assets		**2,170**	1,921
Restricted Investments		**1,497**	1,207
		99,611	98,920
LIABILITIES			
Current Liabilities			
Notes payable		**2,011**	2,762
Accounts payable and other		**4,853**	5,408
Dividends payable		**713**	668
Accrued interest		**611**	646
Current portion of long-term debt		**2,839**	3,462
		11,027	12,946
Regulatory Liabilities		**3,898**	3,930
Other Long-Term Liabilities		**1,634**	1,008
Deferred Income Tax Liabilities		**5,691**	6,026
Long-Term Debt		**36,389**	36,509
Junior Subordinated Notes		**8,771**	7,508
		67,410	67,927
EQUITY			
Common shares, no par value		**24,128**	23,174
Issued and outstanding:	September 30, 2019 – 934 million shares		
	December 31, 2018 – 918 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**—**	17
Retained earnings		**3,569**	2,773
Accumulated other comprehensive loss		**(1,119)**	(606)
Controlling Interests		**30,558**	29,338
Non-controlling interests		**1,643**	1,655
		32,201	30,993
		99,611	98,920

Contingencies and Guarantees (Note 15)

Variable Interest Entities (Note 16)

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of equity

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2019**	**2018**	**2019**	**2018**
Common Shares				
Balance at beginning of period	**23,795**	22,385	**23,174**	21,167
Shares issued:				
Under at-the-market equity issuance program, net of issue costs	**—**	352	**—**	1,118
Under dividend reinvestment and share purchase plan	**240**	209	**684**	640
On exercise of stock options	**93**	5	**270**	26
Balance at end of period	**24,128**	22,951	**24,128**	22,951
Preferred Shares				
Balance at beginning and end of period	**3,980**	3,980	**3,980**	3,980
Additional Paid-In Capital				
Balance at beginning of period	**5**	12	**17**	—
Issuance of stock options, net of exercises	**(8)**	3	**(20)**	8
Reclassification of additional paid-in capital deficit to retained earnings	**3**	—	**3**	—
Dilution from TC PipeLines, LP units issued	**—**	—	**—**	7
Balance at end of period	**—**	15	**—**	15
Retained Earnings				
Balance at beginning of period	**3,534**	2,020	**2,773**	1,623
Net income attributable to controlling interests	**780**	969	**2,991**	2,569
Common share dividends	**(701)**	(631)	**(2,090)**	(1,869)
Preferred share dividends	**(41)**	(40)	**(102)**	(100)
Reclassification of additional paid-in capital deficit to retained earnings	**(3)**	—	**(3)**	—
Adjustment related to income tax effects of asset drop-downs to TC PipeLines, LP	**—**	—	**—**	95
Balance at end of period	**3,569**	2,318	**3,569**	2,318
Accumulated Other Comprehensive Loss				
Balance at beginning of period	**(1,300)**	(1,134)	**(606)**	(1,731)
Other comprehensive income/(loss) attributable to controlling interests	**181**	(216)	**(513)**	381
Balance at end of period	**(1,119)**	(1,350)	**(1,119)**	(1,350)
Equity Attributable to Controlling Interests	**30,558**	27,914	**30,558**	27,914
Equity Attributable to Non-Controlling Interests				
Balance at beginning of period	**1,618**	2,053	**1,655**	1,852
Net income attributable to non-controlling interests	**59**	59	**217**	229
Other comprehensive income/(loss) attributable to non-controlling interests	**15**	(31)	**(66)**	75
Issuance of TC PipeLines, LP units				
Proceeds, net of issue costs	**—**	—	**—**	49
Decrease in TC Energy's ownership of TC PipeLines, LP	**—**	—	**—**	(9)
Distributions declared to non-controlling interests	**(49)**	(58)	**(163)**	(173)
Balance at end of period	**1,643**	2,023	**1,643**	2,023
Total Equity	**32,201**	29,937	**32,201**	29,937

See accompanying notes to the Condensed consolidated financial statements.

Notes to Condensed consolidated financial statements (unaudited)

1. Basis of presentation

On May 3, 2019, TransCanada Corporation changed its name to TC Energy Corporation (TC Energy or the Company). As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

These Condensed consolidated financial statements of TC Energy have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TC Energy's annual audited Consolidated financial statements for the year ended December 31, 2018, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the 2018 audited Consolidated financial statements included in TC Energy's 2018 Annual Report.

These Condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2018 audited Consolidated financial statements included in TC Energy's 2018 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in the Company's natural gas pipelines segments due to the timing of regulatory decisions and seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Liquids Pipelines segment due to fluctuations in throughput volumes on the Keystone Pipeline System and marketing activities. Due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities, earnings for interim periods may not be indicative of results for the fiscal year in the Company's Power and Storage segment.

USE OF ESTIMATES AND JUDGMENTS

In preparing these financial statements, TC Energy is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. In the opinion of management, these Condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the annual audited Consolidated financial statements for the year ended December 31, 2018, except as described in Note 2, Accounting changes.

2. Accounting changes

CHANGES IN ACCOUNTING POLICIES FOR 2019

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statement of income. The new guidance does not make extensive changes to lessor accounting.

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption (January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This transition option allowed the Company to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

The Company elected available practical expedients and exemptions upon adoption which allowed the Company:

- to not reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard
- to carry forward the historical lease classification and its accounting treatment for land easements on existing agreements
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption
- to not separate lease and non-lease components for all leases for which the Company is the lessee and for facility and liquids tank terminals for which the Company is the lessor
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

The new guidance had a significant impact on the Company's Condensed consolidated balance sheet, but did not have an impact on the Company's Condensed consolidated statements of income and cash flows. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases and providing significant new disclosures about the Company's leasing activities. Refer to Note 7, Leases, for additional information related to the impact of adopting the new guidance and the Company's updated accounting policies related to leases.

In the application of the new guidance, significant assumptions and judgments are used to determine the following:

- whether a contract contains a lease
- the duration of the lease term including exercising lease renewal options. The lease term for all of the Company’s leases includes the noncancellable period of the lease plus any additional periods covered by either a Company option to extend (or not to terminate) the lease that the Company is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor
- the discount rate for the lease.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. The Company elected to adopt this guidance effective first quarter 2019. The guidance was applied retrospectively and did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING CHANGES

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that changes how entities measure credit losses for most financial assets and certain other financial instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments, basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than as a direct write-down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. The Company has substantially completed its analysis and does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company has substantially completed its analysis and does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020 and will be applied on a retrospective basis, however, early adoption is permitted. The Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit pension and other post-retirement benefit plans. This new guidance is effective January 1, 2021 and will be applied on a retrospective basis, however, early adoption is permitted. The Company is currently evaluating the timing and impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

3. Segmented information

three months ended September 30, 2019 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage[1]	Corporate[2]	Total
Revenues	**1,016**	**1,176**	**151**	**694**	**96**	**—**	**3,133**
Intersegment revenues	**—**	**40**	**—**	**—**	**4**	**(44)** [3]	**—**
	1,016	**1,216**	**151**	**694**	**100**	**(44)**	**3,133**
Income from equity investments	**4**	**60**	**12**	**18**	**203**	**37** [4]	**334**
Plant operating costs and other	**(380)**	**(393)**	**(11)**	**(185)**	**(51)**	**40** [3]	**(980)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(2)**	**—**	**(2)**
Property taxes	**(68)**	**(86)**	**—**	**(22)**	**(2)**	**—**	**(178)**
Depreciation and amortization	**(289)**	**(192)**	**(27)**	**(83)**	**(19)**	**—**	**(610)**
Gain/(loss) on assets held for sale/sold	**—**	**21**	**—**	**69**	**(202)**	**—**	**(112)**
Segmented Earnings	**283**	**626**	**125**	**491**	**27**	**33**	**1,585**
Interest expense							**(573)**
Allowance for funds used during construction							**120**
Interest income and other[4]							**(19)**
Income before Income Taxes							**1,113**
Income tax expense							**(274)**
Net Income							**839**
Net income attributable to non-controlling interests							**(59)**
Net Income Attributable to Controlling Interests							**780**
Preferred share dividends							**(41)**
Net Income Attributable to Common Shares							**739**

1 Previously referred to as Energy.

2 Includes intersegment eliminations.

3 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

4 Income from equity investments includes foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange losses on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture.

three months ended September 30, 2018 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage[1]	Corporate[2]	Total
Revenues	934	967	156	564	535	—	3,156
Intersegment revenues	—	40	—	—	3	(43) [3]	—
	934	1,007	156	564	538	(43)	3,156
Income/(loss) from equity investments	3	62	8	22	112	(60) [4]	147
Plant operating costs and other	(356)	(313)	(11)	(160)	(79)	35 [3]	(884)
Commodity purchases resold	—	—	—	—	(318)	—	(318)
Property taxes	(59)	(41)	—	(24)	(3)	—	(127)
Depreciation and amortization	(255)	(170)	(26)	(86)	(27)	—	(564)
Segmented Earnings/(Loss)	267	545	127	316	223	(68)	1,410
Interest expense							(577)
Allowance for funds used during construction							147
Interest income and other[4]							168
Income before Income Taxes							1,148
Income tax expense							(120)
Net Income							1,028
Net income attributable to non-controlling interests							(59)
Net Income Attributable to Controlling Interests							969
Preferred share dividends							(41)
Net Income Attributable to Common Shares							928

1 Previously referred to as Energy.

2 Includes intersegment eliminations.

3 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

4 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange gains on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture.

nine months ended September 30, 2019 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage[1]	Corporate[2]	Total
Revenues	2,939	3,691	455	2,233	674	—	9,992
Intersegment revenues	—	123	—	—	15	(138) [3]	—
	2,939	3,814	455	2,233	689	(138)	9,992
Income from equity investments	8	196	22	46	412	11 [4]	695
Plant operating costs and other	(1,085)	(1,127)	(37)	(518)	(175)	126 [3]	(2,816)
Commodity purchases resold	—	—	—	—	(368)	—	(368)
Property taxes	(206)	(258)	—	(77)	(5)	—	(546)
Depreciation and amortization	(862)	(565)	(86)	(260)	(66)	—	(1,839)
Gain/(loss) on assets held for sale/sold	—	21	—	69	(134)	—	(44)
Segmented Earnings/(Loss)	794	2,081	354	1,493	353	(1)	5,074
Interest expense							(1,747)
Allowance for funds used during construction							358
Interest income and other[4]							250
Income before Income Taxes							3,935
Income tax expense							(727)
Net Income							3,208
Net income attributable to non-controlling interests							(217)
Net Income Attributable to Controlling Interests							2,991
Preferred share dividends							(123)
Net Income Attributable to Common Shares							2,868

1 Previously referred to as Energy.

2 Includes intersegment eliminations.

3 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

4 Income from equity investments includes foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange losses on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture.

nine months ended September 30, 2018 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage[1]	Corporate[2]	Total
Revenues	2,772	2,988	460	1,831	1,724	—	9,775
Intersegment revenues	—	121	—	—	50	(171) [3]	—
	2,772	3,109	460	1,831	1,774	(171)	9,775
Income/(loss) from equity investments	9	188	20	50	277	(52) [4]	492
Plant operating costs and other	(1,020)	(925)	(25)	(506)	(250)	146 [3]	(2,580)
Commodity purchases resold	—	—	—	—	(1,239)	—	(1,239)
Property taxes	(200)	(149)	—	(74)	(6)	—	(429)
Depreciation and amortization	(761)	(489)	(73)	(254)	(92)	—	(1,669)
Segmented Earnings/(Loss)	800	1,734	382	1,047	464	(77)	4,350
Interest expense							(1,662)
Allowance for funds used during construction							365
Interest income and other[4]							139
Income before Income Taxes							3,192
Income tax expense							(394)
Net Income							2,798
Net income attributable to non-controlling interests							(229)
Net Income Attributable to Controlling Interests							2,569
Preferred share dividends							(122)
Net Income Attributable to Common Shares							2,447

1 Previously referred to as Energy.
2 Includes intersegment eliminations.
3 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.
4 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange gains on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture.

TOTAL ASSETS BY SEGMENT

(unaudited - millions of Canadian $)	September 30, 2019	December 31, 2018
Canadian Natural Gas Pipelines	**20,874**	18,407
U.S. Natural Gas Pipelines	**42,067**	44,115
Mexico Natural Gas Pipelines	**7,204**	7,058
Liquids Pipelines	**16,135**	17,352
Power and Storage	**7,780**	8,475
Corporate	**5,551**	3,513
	99,611	98,920

4. Revenues

DISAGGREGATION OF REVENUES

The following tables summarize total Revenues for the three and nine months ended September 30, 2019 and 2018:

three months ended September 30, 2019 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**1,016**	**1,008**	**149**	**614**	**—**	**2,787**
Power generation	**—**	**—**	**—**	**—**	**58**	**58**
Natural gas storage and other	**—**	**147**	**2**	**1**	**13**	**163**
	1,016	**1,155**	**151**	**615**	**71**	**3,008**
Other revenues[1]	**—**	**21**	**—**	**79**	**25**	**125**
	1,016	**1,176**	**151**	**694**	**96**	**3,133**

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. These arrangements are not in the scope of the revenue guidance. Refer to Note 7, Leases, and Note 13, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

three months ended September 30, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	934	788	155	511	—	2,388
Power generation	—	—	—	—	450	450
Natural gas storage and other	—	158	1	1	4	164
	934	946	156	512	454	3,002
Other revenues[1]	—	21	—	52	81	154
	934	967	156	564	535	3,156

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. These arrangements are not in the scope of the revenue guidance. Refer to Note 13, Risk management and financial instruments, for additional information on income from financial instruments.

nine months ended September 30, 2019 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**2,939**	**3,140**	**451**	**1,824**	**—**	**8,354**
Power generation	**—**	**—**	**—**	**—**	**599**	**599**
Natural gas storage and other	**—**	**481**	**4**	**3**	**55**	**543**
	2,939	**3,621**	**455**	**1,827**	**654**	**9,496**
Other revenues[1]	**—**	**70**	**—**	**406**	**20**	**496**
	2,939	**3,691**	**455**	**2,233**	**674**	**9,992**

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. These arrangements are not in the scope of the revenue guidance. Refer to Note 7, Leases, and Note 13, Risk management and financial instruments, for additional information on income from lease arrangements and financial instruments, respectively.

nine months ended September 30, 2018 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	2,772	2,457	457	1,558	—	7,244
Power generation	—	—	—	—	1,455	1,455
Natural gas storage and other	—	468	3	2	65	538
	2,772	2,925	460	1,560	1,520	9,237
Other revenues[1]	—	63	—	271	204	538
	2,772	2,988	460	1,831	1,724	9,775

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. These arrangements are not in the scope of the revenue guidance. Refer to Note 13, Risk management and financial instruments, for additional information on income from financial instruments.

CONTRACT BALANCES

(unaudited - millions of Canadian $)	September 30, 2019	December 31, 2018
Receivables from contracts with customers	**1,181**	1,684
Contract assets[1]	**303**	159
Long-term contract assets[2]	**120**	21
Contract liabilities[3]	**56**	11
Long-term contract liabilities[4]	**185**	121

1 Recorded as part of Other current assets on the Condensed consolidated balance sheet.
2 Recorded as part of Intangibles and other assets on the Condensed consolidated balance sheet.
3 Comprised of deferred revenue recorded in Accounts payable and other on the Condensed consolidated balance sheet. During the nine months ended September 30, 2019, $6 million of revenue was recognized that was included in contract liabilities at the beginning of the period.
4 Comprised of deferred revenue recorded in Other long-term liabilities on the Condensed consolidated balance sheet.

Contract assets and long-term contract assets primarily relate to the Company's right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities and long-term contract liabilities primarily relate to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico.

FUTURE REVENUES FROM REMAINING PERFORMANCE OBLIGATIONS

Capacity Arrangements and Transportation

As at September 30, 2019, future revenues from long-term pipeline capacity arrangements and transportation contracts extending through 2045 are approximately $28.4 billion, of which approximately $1.5 billion is expected to be recognized during the remainder of 2019.

Power Generation

The Company has long-term power generation contracts extending through 2028. Revenues from power generation contracts have a variable component related to market prices that are subject to factors outside the Company's influence. These revenues are considered to be fully constrained and are recognized on a monthly basis when the Company satisfies the performance obligation.

Natural Gas Storage and Other

As at September 30, 2019, future revenues from long-term natural gas storage and other contracts extending through 2026 are approximately $0.9 billion, of which approximately $170 million is expected to be recognized during the remainder of 2019.

5. Income taxes

Effective Tax Rates

The effective income tax rates for the nine-month periods ended September 30, 2019 and 2018 were 18 per cent and 12 per cent, respectively. The higher effective tax rate in 2019 was primarily the result of lower foreign tax rate differentials, partially offset by lower flow-through tax in Canadian rate-regulated pipelines.

Further to U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued proposed regulations in November and December of 2018 which provided administrative guidance and clarified certain aspects of the new laws with respect to interest deductibility, base erosion and anti-abuse tax, the new dividend received deduction and anti-hybrid rules. The proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist pending release of the final regulations which is expected to occur in late 2019. If the proposed regulations are enacted as currently drafted, they should not have a material impact on the Company's consolidated financial statements.

Alberta Tax Rate Reduction

In June 2019, a reduction to the Alberta corporate tax rate was enacted. For the Company's Canadian businesses not subject to rate-regulated accounting (RRA), this resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery of $32 million. For the Company's Canadian businesses subject to RRA, this rate change resulted in the reduction of both net deferred income tax liabilities and long-term regulatory assets of $83 million on the Condensed consolidated balance sheet at September 30, 2019.

6. Assets held for sale

Ontario Natural Gas-Fired Power Plants

On July 30, 2019, TC Energy entered into an agreement to sell the Halton Hills and Napanee power plants as well as its 50 per cent interest in Portlands Energy Centre to a third party for proceeds of approximately $2.87 billion, subject to timing of the close and related adjustments. The sale is expected to close by the end of first quarter 2020 subject to conditions which include regulatory approvals and Napanee reaching commercial operations as outlined in the agreement. TC Energy expects this sale to result in a total pre-tax loss of approximately $330 million ($231 million after tax), with $202 million of the pre-tax loss ($133 million after tax) recorded at September 30, 2019 after classifying the net assets as held for sale. The remaining loss will be recorded on or before closing of the transaction.

At September 30, 2019, the related assets and liabilities in the Power and Storage segment were classified as held for sale as follows:

(unaudited - millions of Canadian $)	
Assets Held for Sale	
Inventories	**11**
Plant, property and equipment	**2,501**
Equity investments	**280**
Intangible and other assets	**13**
Total Assets Held for Sale	**2,805**
Liabilities Related to Assets Held for Sale	
Other long-term liabilities	**8**
Total Liabilities Related to Assets Held for Sale[1]	**8**

1 Included in Accounts payable and other on the Condensed consolidated balance sheet.

Coolidge Generating Station

On May 21, 2019, TC Energy completed the sale of its Coolidge generating station, which was reported as Assets held for sale at December 31, 2018. Refer to Note 14, Dispositions, for additional information.

7. Leases

In 2016, the FASB issued new guidance on leases. The Company adopted the new guidance on January 1, 2019 using optional transition relief. Results reported for 2019 reflect the application of the new guidance while the 2018 comparative results were prepared and reported under previous leases guidance.

Lessee Accounting Policy

The Company determines if an arrangement is a lease at inception of the contract. Operating leases are recognized as ROU assets and included in Plant, property and equipment while corresponding liabilities are included in Accounts payable and other, and Other long-term liabilities on the Condensed consolidated balance sheet.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at the commencement date of the lease agreement. As the Company's lease contracts do not provide an implicit interest rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. The operating lease ROU asset also includes any lease payments made and initial direct costs incurred and excludes lease incentives. Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. Operating lease expense is recognized on a straight-line basis over the lease term and included in Plant operating costs and other in the Condensed consolidated statement of income.

Lessor Accounting Policy

The Company is the lessor for certain contracts and these contracts are accounted for as operating leases. The Company recognizes lease payments as income over the lease term on a straight-line basis. Variable lease payments are recognized as income in the period in which the changes in facts and circumstances on which these payments are based occur.

Impact of New Lease Guidance on Date of Adoption

The following table illustrates the impact of the adoption of the new lease guidance on the Company's previously reported consolidated balance sheet line items:

(unaudited - millions of Canadian $)	As reported December 31, 2018	Adjustment	January 1, 2019
Plant, property and equipment	66,503	585	67,088
Accounts payable and other	5,408	57	5,465
Other long-term liabilities	1,008	528	1,536

As a Lessee

The Company has operating leases for corporate offices, other various premises, equipment and land. Some leases have an option to renew for periods of one to 25 years, and some may include options to terminate the lease within one year. Payments due under lease contracts include fixed payments plus, for many of the Company's leases, variable payments such as a proportionate share of the buildings' property taxes, insurance and common area maintenance. The Company subleases some of the leased premises.

Operating lease cost is as follows:

(unaudited - millions of Canadian $)	three months ended September 30, 2019	nine months ended September 30, 2019
Operating lease cost[1]	**29**	**84**
Sublease income	**(3)**	**(8)**
Net operating lease cost	**26**	**76**

1 Includes short-term leases and variable lease costs.

Other information related to operating leases is noted in the following tables:

(unaudited - millions of Canadian $)	three months ended September 30, 2019	nine months ended September 30, 2019
Cash paid for amounts included in the measurement of operating lease liabilities	**19**	**56**
ROU assets obtained in exchange for new operating lease liabilities	**5**	**8**

(unaudited)	at September 30, 2019
Weighted average remaining lease term	**10 years**
Weighted average discount rate	**3.5%**

Maturities of operating lease liabilities on a prospective 12-month basis and where they are disclosed on the Condensed consolidated balance sheet as at September 30, 2019 are as follows:

(unaudited - millions of Canadian $)	
2020	**72**
2021	**69**
2022	**61**
2023	**59**
2024	**58**
Thereafter	**333**
Total operating lease payments	**652**
Imputed interest	**(106)**
Operating lease liabilities recorded on the Condensed consolidated balance sheet	**546**
Reported as follows:	
Accounts payable and other	**56**
Other long-term liabilities	**490**
	546

Future payments reported under previous lease guidance for the Company's operating leases as at December 31, 2018 were as follows:

(unaudited - millions of Canadian $)	**Minimum operating lease payments**
2019	81
2020	78
2021	76
2022	69
2023	67
Thereafter	390
	761

As at September 30, 2019, the carrying value of the ROU assets recorded under operating leases was $544 million and is included in Plant, property and equipment on the Condensed consolidated balance sheet.

As a Lessor

Grandview and Bécancour power plants in the Power and Storage segment and the Northern Courier pipeline in the Liquids Pipelines segment are accounted for as operating leases. The Company has long-term PPAs for the sale of power for the Power and Storage lease assets which expire between 2024 and 2026. Northern Courier pipeline transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal, with a contract expiring in 2042. On July 17, 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier and now uses the equity method to account for its remaining 15 per cent interest in the Company's consolidated financial statements. Refer to Note 14, Dispositions, for additional information. Therefore, only the operating lease income prior to this sale has been included in this lease disclosure.

Some leases contain variable lease payments that are based on operating hours and the reimbursement of variable costs, and options to purchase the underlying asset at fair value or based on a formula considering the remaining fixed payments. Lessees have rights under some leases to terminate under certain circumstances.

The Company also leases liquids tanks which are accounted for as operating leases.

The fixed portion of the operating lease income recorded by the Company for the three and nine months ended September 30, 2019 was $38 million and $149 million, respectively.

Future lease payments to be received under operating leases as at September 30, 2019 are as follows:

(unaudited - millions of Canadian $)	Future lease payments
Remainder of 2019	**32**
2020	**119**
2021	**116**
2022	**111**
2023	**109**
Thereafter	**273**
	760

The cost and accumulated depreciation for facilities accounted for as operating leases was $856 million and $314 million, respectively, at September 30, 2019 (December 31, 2018 – $2,007 million and $324 million, respectively).

8. Long-term debt

LONG-TERM DEBT ISSUED

Long-term debt issued by the Company in the nine months ended September 30, 2019 included the following:

(unaudited - millions of Canadian $) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	September 2019	Medium Term Notes	September 2029	700	3.00%
	September 2019	Medium Term Notes	July 2048	300	4.18%
	April 2019	Medium Term Notes	October 2049	1,000	4.34%
NORTHERN COURIER PIPELINE LIMITED PARTNERSHIP[1]					
	July 2019	Senior Secured Notes	June 2042	1,000	3.365%

1 Subsequent to the debt issuance, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier. The Company's remaining 15 per cent interest is accounted for using the equity method. Refer to Note 14, Dispositions for additional information.

LONG-TERM DEBT REPAID

Long-term debt retired/repaid by the Company in the nine months ended September 30, 2019 included the following:

(unaudited - millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	May 2019	Medium Term Notes	13	9.35%
	March 2019	Debentures	100	10.50%
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%
TC PIPELINES, LP				
	June 2019	Unsecured Term Loan	US 50	Floating
GAS TRANSMISSION NORTHWEST LLC				
	May 2019	Unsecured Term Loan	US 35	Floating

CAPITALIZED INTEREST

In the three and nine months ended September 30, 2019, TC Energy capitalized interest related to capital projects of $48 million and $129 million, respectively (2018 – $33 million and $89 million, respectively).

9. Junior subordinated notes issued

(unaudited - millions of Canadian $, unless notes otherwise) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	September 2019	Junior Subordinated Notes[1,2]	September 2079	US 1,100	5.75%

1 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.
2 The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TC Energy's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

In September 2019, the Trust issued US$1.1 billion of Trust Notes – Series 2019-A (Trust Notes) to third party investors with a fixed interest rate of 5.50 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.1 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.75 per cent, including a 0.25 per cent administration charge. The rate will reset commencing September 2029 until September 2049 to the three month LIBOR plus 4.404 per cent per annum; from September 2049 until September 2079, the interest rate will reset to the three month LIBOR plus 5.154 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after September 15, 2029 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

Pursuant to the terms of the Trust Notes and related agreements, in certain circumstances (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TC Energy and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with any other outstanding first preferred shares of TCPL.

10. Dividends per common share and preferred share

The board of directors of TC Energy declared dividends as follows:

	three months ended September 30		nine months ended September 30	
(unaudited - Canadian $, rounded to two decimals)	**2019**	**2018**	**2019**	**2018**
per common share	**$0.75**	$0.69	**$2.25**	$2.07
per Series 1 preferred share	**$0.20**	$0.20	**$0.61**	$0.61
per Series 2 preferred share	**$0.23**	$0.20	**$0.68**	$0.57
per Series 3 preferred share	**$0.13**	$0.13	**$0.40**	$0.40
per Series 4 preferred share	**$0.19**	$0.16	**$0.56**	$0.45
per Series 5 preferred share	**$0.14**	$0.14	**$0.42**	$0.42
per Series 6 preferred share	**$0.20**	$0.18	**$0.60**	$0.50
per Series 7 preferred share	**$0.24**	$0.25	**$0.74**	$0.75
per Series 9 preferred share	**$0.27**	$0.27	**$0.80**	$0.80
per Series 11 preferred share	**$0.24**	$0.24	**$0.48**	$0.48
per Series 13 preferred share	**$0.34**	$0.34	**$0.69**	$0.69
per Series 15 preferred share	**$0.31**	$0.31	**$0.61**	$0.61

Shareholders of the Series 9 preferred shares had the option to convert to Series 10 preferred shares by providing notice on or before October 15, 2019. As the total number of Series 9 preferred shares tendered for conversion did not meet the established threshold, no Series 9 preferred shares were subsequently converted into Series 10 preferred shares.

11. Other comprehensive income/(loss) and accumulated other comprehensive loss

Components of other comprehensive income/(loss), including the portion attributable to non-controlling interests and related tax effects, are as follows:

three months ended September 30, 2019 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	**219**	**6**	**225**
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**(4)**	**—**	**(4)**
Change in fair value of net investment hedges	**(12)**	**3**	**(9)**
Change in fair value of cash flow hedges	**(34)**	**8**	**(26)**
Reclassification to net income of gains and losses on cash flow hedges	**5**	**(1)**	**4**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**4**	**(1)**	**3**
Other comprehensive income on equity investments	**3**	**—**	**3**
Other Comprehensive Income	**181**	**15**	**196**

three months ended September 30, 2018 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	(273)	(9)	(282)
Change in fair value of net investment hedges	12	(3)	9
Change in fair value of cash flow hedges	5	(1)	4
Reclassification to net income of gains and losses on cash flow hedges	8	(2)	6
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	4	6	10
Other comprehensive income on equity investments	7	(1)	6
Other Comprehensive Loss	(237)	(10)	(247)

nine months ended September 30, 2019 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	**(516)**	**(14)**	**(530)**
Reclassification of foreign currency translation gains on net investment on disposal of foreign operations	**(13)**	**—**	**(13)**
Change in fair value of net investment hedges	**32**	**(8)**	**24**
Change in fair value of cash flow hedges	**(108)**	**23**	**(85)**
Reclassification to net income of gains and losses on cash flow hedges	**13**	**(3)**	**10**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**11**	**(3)**	**8**
Other comprehensive income on equity investments	**1**	**6**	**7**
Other Comprehensive Loss	**(580)**	**1**	**(579)**

nine months ended September 30, 2018 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	397	12	409
Change in fair value of net investment hedges	(8)	2	(6)
Change in fair value of cash flow hedges	8	1	9
Reclassification to net income of gains and losses on cash flow hedges	21	(5)	16
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	12	(2)	10
Other comprehensive income on equity investments	20	(2)	18
Other Comprehensive Income	450	6	456

The changes in AOCI by component are as follows:

three months ended September 30, 2019 (unaudited - millions of Canadian $)	**Currency Translation Adjustments**	**Cash Flow Hedges**	**Pension and OPEB Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at July 1, 2019	**(557)**	**(63)**	**(309)**	**(371)**	**(1,300)**
Other comprehensive income/(loss) before reclassifications[2]	**198**	**(25)**	**—**	**—**	**173**
Amounts reclassified from AOCI[3]	**(4)**	**6**	**3**	**3**	**8**
Net current period other comprehensive income/(loss)	**194**	**(19)**	**3**	**3**	**181**
AOCI balance at September 30, 2019	**(363)**	**(82)**	**(306)**	**(368)**	**(1,119)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive income/(loss) before reclassifications on currency translation adjustments and cash flow hedges are net of non-controlling interests gains of $18 million and losses of $1 million, respectively.

3 Amount reclassified from AOCI on cash flow hedges is net of non-controlling interests gains of $2 million.

nine months ended September 30, 2019 (unaudited - millions of Canadian $)	**Currency Translation Adjustments**	**Cash Flow Hedges**	**Pension and OPEB Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at January 1, 2019	**107**	**(23)**	**(314)**	**(376)**	**(606)**
Other comprehensive loss before reclassifications[2]	**(457)**	**(70)**	**—**	**(1)**	**(528)**
Amounts reclassified from AOCI[3,4]	**(13)**	**11**	**8**	**9**	**15**
Net current period other comprehensive (loss)/income	**(470)**	**(59)**	**8**	**8**	**(513)**
AOCI balance at September 30, 2019	**(363)**	**(82)**	**(306)**	**(368)**	**(1,119)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive loss before reclassifications on currency translation adjustments, cash flow hedges and equity investments are net of non-controlling interests losses of $49 million, $15 million and $1 million, respectively.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $21 million ($16 million, net of tax) at September 30, 2019. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

4 Amount reclassified from AOCI on cash flow hedges is net of non-controlling interests gains of $1 million.

Details about reclassifications out of AOCI into the Condensed consolidated statement of income are as follows:

	Amounts Reclassified From AOCI				
	three months ended September 30		nine months ended September 30		Affected line item in the Condensed consolidated statement of income
(unaudited - millions of Canadian $)	2019	2018	2019	2018	
Cash flow hedges					
Commodities	**(4)**	(3)	**(4)**	(4)	Revenues (Power and Storage)
Interest rate	**(3)**	(4)	**(10)**	(13)	Interest expense
	(7)	(7)	**(14)**	(17)	Total before tax
	1	2	**3**	5	Income tax expense
	(6)	(5)	**(11)**	(12)	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments					
Amortization of actuarial losses	**(4)**	(4)	**(11)**	(12)	Plant operating costs and other[2]
	1	(6)	**3**	2	Income tax expense
	(3)	(10)	**(8)**	(10)	Net of tax[1]
Equity investments					
Equity income	**(3)**	(6)	**(9)**	(19)	Income from equity investments
	—	1	**—**	3	Income tax expense
	(3)	(5)	**(9)**	(16)	Net of tax[1,3]
Currency translation adjustments					
Realization of foreign currency translation gain on disposal of foreign operations	**4**	—	**13**	—	Gain/(loss) on assets held for sale/sold
	—	—	**—**	—	Income tax expense
	4	—	**13**	—	Net of tax[1]

1 All amounts in parentheses indicate expenses to the Condensed consolidated statement of income.

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 12, Employee post-retirement benefits, for additional information.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interests gains of $2 million and nil, respectively, for the three months ended September 30, 2019 (2018 – $1 million and $1 million, respectively) and gains of $1 million and nil, respectively, for the nine months ended September 30, 2019 (2018 – $4 million and $2 million, respectively).

12. Employee post-retirement benefits

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans is as follows:

	three months ended September 30				nine months ended September 30			
	Pension benefit plans		Other post-retirement benefit plans		Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**	**2019**	**2018**
Service cost[1]	**31**	30	**1**	1	**95**	91	**4**	3
Other components of net benefit cost[1]								
Interest cost	**36**	33	**5**	3	**107**	100	**13**	10
Expected return on plan assets	**(55)**	(55)	**(4)**	(4)	**(167)**	(165)	**(12)**	(12)
Amortization of actuarial losses	**3**	4	**1**	—	**9**	11	**2**	1
Amortization of regulatory asset	**3**	5	**—**	—	**10**	14	**1**	—
	(13)	(13)	**2**	(1)	**(41)**	(40)	**4**	(1)
Net Benefit Cost	**18**	17	**3**	—	**54**	51	**8**	2

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Condensed consolidated statement of income.

13. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

TC Energy has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings, cash flow and shareholder value.

COUNTERPARTY CREDIT RISK

TC Energy's maximum counterparty credit exposure with respect to financial instruments at September 30, 2019, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available-for-sale assets, the fair value of derivative assets and a loan receivable.

The Company monitors its counterparties and reviews its accounts receivable regularly and, if needed, the Company records an allowance for doubtful accounts using the specific identification method. At September 30, 2019, there were no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

Continued low natural gas prices have presented increased financial challenges to certain of the Company's WCSB and Appalachian natural gas pipeline shippers. The Company does not expect these shipper challenges to result in any material negative impact to its earnings or cash flow.

LOAN RECEIVABLE FROM AFFILIATE

Related party transactions are conducted in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

The Company holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. The Company accounts for its interest in the joint venture as an equity investment. In 2017, the Company entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022.

At September 30, 2019, the Company's Condensed consolidated balance sheet included a MXN$20.9 billion or $1.4 billion (December 31, 2018 – MXN$18.9 billion or $1.3 billion) loan receivable from the Sur de Texas joint venture which represents TC Energy's proportionate share of long-term debt financing requirements related to the joint venture. Interest income and other included interest income of $38 million and $110 million for the three and nine months ended September 30, 2019 (2018 – $32 million and $88 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments in the Company's Mexico Natural Gas Pipelines segment. As a result, there is no impact to net income.

NET INVESTMENT IN FOREIGN OPERATIONS

The Company hedges a portion of its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange options.

The fair values and notional amounts for the derivatives designated as a net investment hedge were as follows:

	September 30, 2019		December 31, 2018	
(unaudited - millions of Canadian $, unless otherwise noted)	Fair value[1,2]	Notional amount	Fair value[1,2]	Notional amount
U.S. dollar cross-currency swaps[3]	—	—	(43)	US 300
U.S. dollar foreign exchange options (maturing 2019 to 2020)	**(4)**	**US 2,500**	(47)	US 2,500
	(4)	**US 2,500**	(90)	US 2,800

1 Fair value equals carrying value.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In the three and nine months ended September 30, 2019, Net income includes net realized gains of nil (2018 – nil and $1 million, respectively) related to the interest component of cross-currency swap settlements which are reported within Interest expense on the Company's Condensed consolidated statement of income.

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

(unaudited - millions of Canadian $, unless otherwise noted)	September 30, 2019	December 31, 2018
Notional amount	**29,700 (US 22,500)**	31,000 (US 22,700)
Fair value	**33,500 (US 25,300)**	31,700 (US 23,200)

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

Available-for-sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Intangible and other assets, Notes payable, Accounts payable and other, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity. Each of these instruments are classified in Level II of the fair value hierarchy.

Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of the Company's non-derivative financial instruments, excluding those where carrying amounts approximate fair value, which are classified in Level II of the fair value hierarchy:

	September 30, 2019		December 31, 2018	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt including current portion[1,2]	**(39,228)**	**(45,502)**	(39,971)	(42,284)
Junior subordinated notes	**(8,771)**	**(8,684)**	(7,508)	(6,665)
	(47,999)	**(54,186)**	(47,479)	(48,949)

1 Long-term debt is recorded at amortized cost except for US$450 million (December 31, 2018 – US$750 million) that is attributed to hedged risk and recorded at fair value.

2 Net income for the three and nine months ended September 30, 2019 includes unrealized gains of $1 million and losses of $4 million, respectively (2018 – unrealized losses of $1 million and unrealized gains of $3 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$450 million of long-term debt at September 30, 2019 (December 31, 2018 – US$750 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-sale assets summary

The following tables summarize additional information about the Company's restricted investments that are classified as available-for-sale assets:

	September 30, 2019		December 31, 2018	
(unaudited - millions of Canadian $)	LMCI restricted investments	Other restricted investments[1]	LMCI restricted investments	Other restricted investments[1]
Fair values of fixed income securities[2]				
Maturing within 1 year	**—**	**16**	—	22
Maturing within 1-5 years	**51**	**97**	—	110
Maturing within 5-10 years	**734**	**—**	140	—
Maturing after 10 years	**58**	**—**	952	—
Fair value of equity securities[2]	**528**	**—**	—	—
	1,371	**113**	1,092	132

1 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

2 Available-for-sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Company's Condensed consolidated balance sheet.

	September 30, 2019		September 30, 2018	
(unaudited - millions of Canadian $)	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized (losses)/gains in the period				
three months ended	**(57)**	**—**	(34)	—
nine months ended	**22**	**3**	(29)	1
Net realized gains/(losses) in the period				
three months ended	**48**	**—**	—	—
nine months ended	**59**	**—**	(3)	—

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory assets or liabilities.

2 Gains and losses on other restricted investments are included in Interest income and other in the Condensed consolidated statement of income.

Derivative instruments

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses period-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments is as follows:

at September 30, 2019 (unaudited - millions of Canadian $)	**Cash Flow Hedges**	**Fair Value Hedges**	**Net Investment Hedges**	**Held for Trading**	**Total Fair Value of Derivative Instruments**[1]
Other current assets					
Commodities[2]	—	—	—	**195**	**195**
Foreign exchange	—	—	**5**	**11**	**16**
	—	—	**5**	**206**	**211**
Intangible and other assets					
Commodities[2]	—	—	—	**48**	**48**
Foreign exchange	—	—	**2**	—	**2**
Interest rate	—	**2**	—	—	**2**
	—	**2**	**2**	**48**	**52**
Total Derivative Assets	—	**2**	**7**	**254**	**263**
Accounts payable and other					
Commodities[2]	**(6)**	—	—	**(168)**	**(174)**
Foreign exchange	—	—	**(10)**	**(22)**	**(32)**
Interest rate	**(7)**	—	—	—	**(7)**
	(13)	—	**(10)**	**(190)**	**(213)**
Other long-term liabilities					
Commodities[2]	**(5)**	—	—	**(59)**	**(64)**
Foreign exchange	—	—	**(1)**	—	**(1)**
Interest rate	**(89)**	—	—	—	**(89)**
	(94)	—	**(1)**	**(59)**	**(154)**
Total Derivative Liabilities	**(107)**	—	**(11)**	**(249)**	**(367)**
Total Derivatives	**(107)**	**2**	**(4)**	**5**	**(104)**

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas and liquids.

at December 31, 2018 (unaudited - millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets					
Commodities[2]	1	—	—	716	717
Foreign exchange	—	—	16	1	17
Interest rate	3	—	—	—	3
	4	—	16	717	737
Intangible and other assets					
Commodities[2]	1	—	—	50	51
Foreign exchange	—	—	1	—	1
Interest rate	8	1	—	—	9
	9	1	1	50	61
Total Derivative Assets	13	1	17	767	798
Accounts payable and other					
Commodities[2]	(4)	—	—	(622)	(626)
Foreign exchange	—	—	(105)	(188)	(293)
Interest rate	—	(3)	—	—	(3)
	(4)	(3)	(105)	(810)	(922)
Other long-term liabilities					
Commodities[2]	—	—	—	(28)	(28)
Foreign exchange	—	—	(2)	—	(2)
Interest rate	(11)	(1)	—	—	(12)
	(11)	(1)	(2)	(28)	(42)
Total Derivative Liabilities	(15)	(4)	(107)	(838)	(964)
Total Derivatives	(2)	(3)	(90)	(71)	(166)

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas and liquids.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Condensed consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

	Carrying amount		Fair value hedging adjustments[1]	
(unaudited - millions of Canadian $)	**September 30, 2019**	**December 31, 2018**	**September 30, 2019**	**December 31, 2018**
Current portion of long-term debt	**(331)**	(748)	**—**	3
Long-term debt	**(267)**	(273)	**(2)**	—
	(598)	(1,021)	**(2)**	3

1 At September 30, 2019 and December 31, 2018, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and maturity summary

The maturity and notional amount or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations is as follows:

at September 30, 2019 (unaudited)	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**418**	**14**	**39**	**—**	**—**
Sales[1]	**2,353**	**24**	**62**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,268**	**1,850**
Millions of Mexican pesos	**—**	**—**	**—**	**500**	**—**
Maturity dates	**2019-2024**	**2019-2027**	**2019-2020**	**2019-2020**	**2019-2030**

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

at December 31, 2018 (unaudited)	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	23,865	44	59	—	—
Sales[1]	17,689	56	79	—	—
Millions of U.S. dollars	—	—	—	3,862	1,650
Maturity dates	2019-2023	2019-2027	2019	2019	2019-2030

1 Volumes for power, natural gas and liquids derivatives are in GWh, Bcf and MMBbls, respectively.

Unrealized and realized (losses)/gains on derivative instruments

The following summary does not include hedges of the net investment in foreign operations:

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	2019	2018	2019	2018
Derivative Instruments Held for Trading[1]				
Amount of unrealized (losses)/gains in the period				
Commodities[2]	**(69)**	(31)	**(98)**	(41)
Foreign exchange	**(31)**	60	**176**	(79)
Amount of realized gains/(losses) in the period				
Commodities	**132**	81	**319**	210
Foreign exchange	**(9)**	(5)	**(68)**	14
Derivative Instruments in Hedging Relationships				
Amount of realized gains/(losses) in the period				
Commodities	**1**	1	**(8)**	—
Interest rate	**1**	(2)	**1**	(1)

1 Realized and unrealized gains and losses on held-for-trading derivative instruments used to purchase and sell commodities are included on a net basis in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held-for-trading derivative instruments are included on a net basis in Interest expense and Interest income and other, respectively.

2 In the three and nine months ended September 30, 2019 and 2018, there were no gains or losses included in Net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI (Note 11) related to the change in fair value of derivatives in cash flow hedging relationships before tax and including the portion attributable to non-controlling interests are as follows:

(unaudited - millions of Canadian $)	three months ended September 30		nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Change in fair value of derivative instruments recognized in OCI[1]				
Commodities	**1**	3	**(13)**	(3)
Interest rate	**(35)**	2	**(95)**	11
	(34)	5	**(108)**	8

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI and AOCI.

Effect of fair value and cash flow hedging relationships

The following tables detail amounts presented in the Condensed consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded:

(unaudited - millions of Canadian $)	three months ended September 30			
	Revenues (Power and Storage)		Interest Expense	
	2019	**2018**	**2019**	**2018**
Total Amount Presented in the Condensed Consolidated Statement of Income	**96**	535	**(573)**	(577)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(5)**	(17)
Derivatives designated as hedging instruments	**—**	—	**1**	(2)
Cash Flow Hedges				
Reclassification of losses on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**(1)**	(5)
Commodity contracts	**(4)**	(3)	**—**	—

1 Refer to Note 11, Other comprehensive income/(loss) and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

(unaudited - millions of Canadian $)	nine months ended September 30			
	Revenues (Power and Storage)		Interest Expense	
	2019	2018	2019	2018
Total Amount Presented in the Condensed Consolidated Statement of Income	**674**	1,724	**(1,747)**	(1,662)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(16)**	(59)
Derivatives designated as hedging instruments	**—**	—	**—**	(4)
Cash Flow Hedges				
Reclassification of losses on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**(9)**	(17)
Commodity contracts	**(4)**	(4)	**—**	—

1 Refer to Note 11, Other comprehensive income/(loss) and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

Offsetting of derivative instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TC Energy has no master netting agreements, however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis on the Condensed consolidated balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at September 30, 2019 (unaudited - millions of Canadian $)	Gross derivative instruments	Amounts available for offset[1]	Net amounts
Derivative instrument assets			
Commodities	**243**	**(197)**	**46**
Foreign exchange	**18**	**(12)**	**6**
Interest rate	**2**	**(2)**	**—**
	263	**(211)**	**52**
Derivative instrument liabilities			
Commodities	**(238)**	**197**	**(41)**
Foreign exchange	**(33)**	**12**	**(21)**
Interest rate	**(96)**	**2**	**(94)**
	(367)	**211**	**(156)**

1 Amounts available for offset do not include cash collateral pledged or received.

at December 31, 2018 (unaudited - millions of Canadian $)	Gross derivative instruments	Amounts available for offset[1]	Net amounts
Derivative instrument assets			
Commodities	768	(626)	142
Foreign exchange	18	(18)	—
Interest rate	12	(4)	8
	798	(648)	150
Derivative instrument liabilities			
Commodities	(654)	626	(28)
Foreign exchange	(295)	18	(277)
Interest rate	(15)	4	(11)
	(964)	648	(316)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above, at September 30, 2019, the Company provided cash collateral of $47 million (December 31, 2018 – $143 million) and letters of credit of $20 million (December 31, 2018 – $22 million) to its counterparties. At September 30, 2019, the Company held no cash collateral and no letters of credit from counterparties on asset exposures (December 31, 2018 – nil and $1 million, respectively).

Credit-risk-related contingent features of derivative instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade. The Company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at September 30, 2019, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $5 million (December 31, 2018 – $6 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on September 30, 2019, the Company would have been required to provide collateral of $5 million (December 31, 2018 – $6 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

FAIR VALUE HIERARCHY

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date. An active market is a market in which frequency and volume of transactions provides pricing information on an ongoing basis.
Level II	This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.
Level III	This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. There is uncertainty caused by using unobservable market data which may not accurately reflect possible future changes in fair value.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions are categorized as follows:

at September 30, 2019 (unaudited - millions of Canadian $)	Quoted prices in active markets (Level I)	Significant other observable inputs (Level II)[1]	Significant unobservable inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	**195**	**48**	**—**	**243**
Foreign exchange	**—**	**18**	**—**	**18**
Interest rate	**—**	**2**	**—**	**2**
Derivative instrument liabilities				
Commodities	**(199)**	**(32)**	**(7)**	**(238)**
Foreign exchange	**—**	**(33)**	**—**	**(33)**
Interest rate	**—**	**(96)**	**—**	**(96)**
	(4)	**(93)**	**(7)**	**(104)**

1 There were no transfers from Level II to Level III for the nine months ended September 30, 2019.

at December 31, 2018 (unaudited - millions of Canadian $)	Quoted prices in active markets (Level I)	Significant other observable inputs (Level II)[1]	Significant unobservable inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	581	187	—	768
Foreign exchange	—	18	—	18
Interest rate	—	12	—	12
Derivative instrument liabilities				
Commodities	(555)	(95)	(4)	(654)
Foreign exchange	—	(295)	—	(295)
Interest rate	—	(15)	—	(15)
	26	(188)	(4)	(166)

1 There were no transfers from Level II to Level III for the year ended December 31, 2018.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

	three months ended September 30		nine months ended September 30	
(unaudited - millions of Canadian $)	**2019**	2018	**2019**	2018
Balance at beginning of period	**(7)**	40	**(4)**	(7)
Total losses included in Net income	**—**	(24)	**(3)**	(6)
Settlements	**—**	(14)	**—**	9
Transfers out of Level III	**—**	(16)	**—**	(10)
Balance at end of period[1]	**(7)**	(14)	**(7)**	(14)

1 For the three and nine months ended September 30, 2019, Revenues included unrealized gains of less than $1 million and losses of $3 million, respectively, attributed to derivatives in the Level III category that were still held at September 30, 2019 (2018 – unrealized losses of $16 million and $2 million, respectively).

14. Dispositions

Coolidge Generating Station

In December 2018, the Company entered into an agreement to sell its Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal (ROFR) on a sale to a third party and the Company terminated the agreement with SWG.

On May 21, 2019, the Company completed the sale to SRP as per the terms of their ROFR, for proceeds of US$448 million before post-closing adjustments. As a result, the Company recorded a pre-tax gain on sale of $68 million ($54 million after tax) including the impact of $9 million of foreign currency translation gains which were reclassified from AOCI to net income. The pre-tax gain is included in Gain/(loss) on assets held for sale/sold in the Condensed consolidated statement of income.

Northern Courier

On July 17, 2019, TC Energy completed the sale of an 85 per cent equity interest in Northern Courier to a third party for gross proceeds of $144 million, before post-closing adjustments, resulting in a pre-tax gain of $69 million after recording the Company's remaining 15 per cent interest at fair value. The pre-tax gain is included in Gain/(loss) on assets held for sale/sold in the Condensed consolidated statement of income. On an after-tax basis, the gain of $115 million reflects the utilization of previously unrecognized tax loss benefits. Preceding the equity sale, Northern Courier issued $1.0 billion of long-term, non-recourse debt, the proceeds from which were paid to TC Energy, resulting in aggregate gross proceeds to TC Energy of $1.15 billion from this asset monetization.

TC Energy remains the operator of the Northern Courier pipeline and is using the equity method to account for its remaining 15 per cent interest in the Company's consolidated financial statements.

Columbia Midstream Assets

On August 1, 2019, TC Energy completed the sale of certain Columbia Midstream assets to a third party for approximately US$1.3 billion before post-closing adjustments.

The Company recorded a pre-tax gain on sale of $21 million ($133 million after-tax loss), which included a $4 million foreign currency translation gain and the release of $595 million of Columbia's goodwill allocated to these assets that is not deductible for income tax purposes. The pre-tax gain is included in Gain/(loss) on assets held for sale/sold in the Condensed consolidated statement of income. This sale does not include any interest in Columbia Energy Ventures Company, the Company's minerals business in the Appalachian basin.

15. Contingencies and guarantees

CONTINGENCIES

TC Energy and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

GUARANTEES

As part of its role as operator of the pipeline, TC Energy has guaranteed the financial performance of the Northern Courier pipeline related to delivery and terminalling of bitumen and diluent and contingent financial obligations under sub-lease agreements.

TC Energy and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of this entity. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas.

TC Energy and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services.

The Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services and the payment of liabilities. For certain of these entities, any payments made by TC Energy under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in Accounts payable and other and Other long-term liabilities on the Condensed consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		at September 30, 2019		at December 31, 2018	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Northern Courier	ranging to 2055	**300**	**27**	—	—
Sur de Texas	ranging to 2020	**167**	**1**	183	1
Bruce Power	ranging to 2021	**88**	**—**	88	—
Other jointly-owned entities	ranging to 2059	**100**	**10**	104	11
		655	**38**	375	12

1 TC Energy's share of the potential estimated current or contingent exposure.

16. Variable interest entities

A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity.

In the normal course of business, the Company consolidates VIEs in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs in which the Company has a variable interest but is not the primary beneficiary are considered non-consolidated VIEs and are accounted for as equity investments.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company is the primary beneficiary. As the primary beneficiary, the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The Consolidated VIEs whose assets cannot be used for purposes other than the settlement of the VIE's obligations, or are not considered a business, are as follows:

(unaudited - millions of Canadian $)	September 30, 2019	December 31, 2018
ASSETS		
Current Assets		
Cash and cash equivalents	**119**	45
Accounts receivable	**61**	79
Inventories	**25**	24
Other	**6**	13
	211	161
Plant, Property and Equipment	**3,095**	3,026
Equity Investments	**810**	965
Goodwill	**440**	453
Intangible and Other Assets	**—**	8
	4,556	4,613
LIABILITIES		
Current Liabilities		
Accounts payable and other	**72**	88
Accrued interest	**29**	24
Current portion of long-term debt	**191**	79
	292	191
Regulatory Liabilities	**44**	43
Other Long-Term Liabilities	**11**	3
Deferred Income Tax Liabilities	**12**	13
Long-Term Debt	**2,753**	3,125
	3,112	3,375

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company is not the primary beneficiary as it does not have the power to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid.

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs are as follows:

(unaudited - millions of Canadian $)	September 30, 2019	December 31, 2018
Balance sheet		
Equity investments	**4,473**	4,575
Off-balance sheet		
Potential exposure to guarantees	**466**	170
Maximum exposure to loss	**4,939**	4,745